UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _______**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS PRC-027-1 AND PER-006-1 AND RETIREMENT OF PRC-001-1.1(ii)

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval:

- proposed Reliability Standards PRC-027-1 and PER-006-1 (Exhibit A);
- proposed new and revised definitions to be incorporated into the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") for the following terms: (1) Protection System Coordination Study; (2) Operational Planning Analysis ("OPA"); and (3) Real-time Assessment ("RTA") (Exhibit A);
- the retirement of Reliability Standard PRC-001-1.1(ii);
- the associated Implementation Plans (Exhibit B); and
- the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (Exhibit F).[4]

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[1] 16 U.S.C. § 824o (2012).

[2] 18 C.F.R. § 39.5 (2016).

[3] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

[4] Unless otherwise designated, all capitalized terms used herein shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

As required by Section 39.5(a) of the Commission's regulations,[5] this Petition presents the technical basis and purpose of the proposed Reliability Standards and NERC Glossary definitions, a summary of the development history (Exhibit G), and a demonstration that the proposed Reliability Standards and definitions meet the criteria identified by the Commission in Order No. 672[6] (Exhibit C). The NERC Board of Trustees ("Board") adopted proposed Reliability Standard PRC-027-1 and the definition of Protection System Coordination Study on November 5, 2015, and proposed Reliability Standard PER-006-1 and the modified definitions of OPA and RTA on August 11, 2016.

I. EXECUTIVE SUMMARY

The purpose of the proposed Reliability Standards and the proposed NERC Glossary definitions is to: (1) maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System ("BES") Elements, such that those Protection Systems operate in the intended sequence during Faults; and (2) require registered entities to provide training to their relevant personnel on Protection Systems and Remedial Action Schemes ("RAS") to help ensure that the BES is reliably operated. The reliable and coordinated operation of Protection Systems is essential to Bulk Power System ("BPS") reliability for the following reasons. Protection Systems help maintain reliability by isolating faulted equipment, thereby reducing the risk of instability or Cascading, and leaving the remainder of the BPS operational and more capable of withstanding a future Contingency. In the event of a Fault, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage.

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5 18 C.F.R. § 39.5(a) (2016).

6 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at PP 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

System reliability is reduced or threatened if a Protection System can no longer perform as designed because of a failure of its relays. Further, the functions, settings, and limitations of Protection Systems are recognized and integrated in deriving System Operating Limits ("SOLs") and Interconnection Reliability Operating Limits ("IROLs").[7]

Issues related to the coordination of Protection Systems are currently addressed in Reliability Standard PRC-001-1.1(ii), which includes the following six requirements:

- *Requirement R1* provides that "[e]ach Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area."

- *Requirement R2* provides that Generator Operators and Transmission Operators shall notify certain other entities of relay or equipment failures that reduce system reliability and take corrective action as soon as possible.

- *Requirement R3* addresses the coordination of new protective systems and changes to existing protective systems.

- *Requirement R4* provides that Transmission Operators must coordinate Protection Systems on major transmission lines and interconnections with certain neighboring entities.

- *Requirement R5* requires Generator Operators and Transmission Operators to coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others.

- *Requirement R6* requires Transmission Operators and Balancing Authorities to monitor the status of each Special Protection System ("SPS") in their area and notify affected entities of any change in status.

As explained further below, NERC is proposing to retire Reliability Standard PRC-001-1.1(ii). The Requirements in PRC-001-1.1(ii) are being replaced by proposed Reliability Standards PRC-027-1 and PER-006-1 and the proposed definitions, or are addressed by Reliability Standards approved by the Commission since the effective date of PRC-001-1, as follows:

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[7] SOLs and IROLs are vital concepts in NERC's Reliability Standards as they establish acceptable performance criteria both pre- and post-contingency to maintain reliable Bulk Electric System operations.

PRC-001-1.1(ii) Requirement R1: Along with currently-effective Personnel Performance, Training, and Qualifications ("PER") Reliability Standards, proposed Reliability Standard PER-006-1 and the proposed modifications to the definitions of OPA and RTA are designed to improve upon and replace PRC-001-1.1(ii), Requirement R1 in addressing the reliability goal of requiring Generator Operators, Balancing Authorities, and Transmission Operations to be "familiar with" the purpose and limitations of Protection System schemes. Focusing on the certification and training requirements in the PER group of Reliability Standards as the mechanism for ensuring that the necessary personnel are familiar with the purpose and limitations of Protection System schemes will provide more precise and auditable requirements to achieve the reliability objective of Requirement R1 of PRC-001-1.1(ii). Currently-effective PER-005-2, Requirement R6 already requires Generator Operators to provide training to their centrally-located dispatch personnel on how their job functions impact BES reliability. Proposed PER-006-1 adds a requirement in the PER standards that Generator Operators train their plant operating personnel on the operational functionality of Protection Systems and RAS that affect the output of their generating Facilities.[8] For Transmission Operators and Balancing Authorities, the reliability goal of Requirement R1 is addressed by the currently-effective certification and training requirements in PER-003-1 and PER-005-2, respectively.

Additionally, the proposed modifications to the definitions of OPA and RTA further the objective of PRC-001-1.1(ii), Requirement R1 by requiring that Transmission Operators, as well as Reliability Coordinators, consider the functions and limitations of Protection Systems and RAS when performing the OPAs and RTAs required under the Transmission Operations ("TOP") and

[8] The phrase "Protection System schemes" in PRC-001-1.1(ii), Requirement R1 maps to the NERC Glossary terms "Protection Systems" and "Remedial Action Schemes," as explained below.

Interconnection Reliability Operations and Coordination ("IRO") group of Reliability Standards to determine whether there are any actual or expected SOL or IROL exceedances.

PRC-001-1.1(ii) Requirement R2: The reliability goal of PRC-001-1.1(ii) Requirement R2 for Generator Operators and Transmission Operators to notify certain other entities of certain relay or equipment failures and take corrective action as soon as possible is addressed in recently approved Reliability Standards IRO-001-4, IRO-008-2, IRO-010-2, TOP-001-3, and TOP-003-3.[9] As discussed below, these standards collectively require, among others things, that (1) Reliability Coordinators, Balancing Authorities, and Transmission Operators maintain reliability in their area by their own actions or by directing the actions of others (e.g., taking corrective action in event of relay or equipment failure), and (2) require other registered entities to provide Reliability Coordinators and Transmission Operators with data or notifications under certain circumstances, including notifications regarding the status or degradation of Protection Systems and SPS.[10]

PRC-001-1.1(ii) Requirements R3 and R4: Proposed Reliability Standard PRC-027-1 is designed to improve upon and replace Requirements R3 and R4 of PRC-001-1.1(ii) in addressing the reliability objective of Protection System coordination. Proposed Reliability Standard PRC-027-1 provides a clear set of Requirements that obligate applicable entities to (1) implement a process for establishing and coordinating new or revised Protection System settings and (2) periodically study Protection System settings that could be affected by incremental changes in

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9 These Reliability Standards – along with IRO-002-4, IRO-014-3, IRO-017-1, and TOP-002-4 – were approved in Order No. 817. *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178, 80 Fed. Reg. 73977 (2015).

10 Per the Commission's order approving the revised definition of SPS on June 23, 2016, SPS and RAS are interchangeable terms. *See N. Am. Elec. Reliability Corp.*, Docket No. RD16-5-000 (June 23, 2016) (unpublished letter order). This Petition uses the NERC Glossary terms "RAS" or "SPS" depending on the language in the Requirement the Petition is discussing. If the Petition is discussing a Requirement that uses RAS, for instance, the Petition will refer to RAS when discussing that Requirement.

Fault current to ensure they continue to be appropriate (i.e., that the Protection System continues to operate in the intended sequence during Faults).

PRC-001-1.1(ii) Requirement R5: The reliability objective of coordinating changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others is now primarily addressed by Reliability Standard TOP-003-3, as well as Reliability Standards TOP-001-3, TOP-002-4, IRO-008-2, IRO-010-2, and IRO-017-1, which were developed since PRC-001-1.1(ii) went into effect. As discussed further below, these Reliability Standards require coordination and analysis of changes in conditions that would necessitate changes to the Protection Systems of others, amongst other actions.

PRC-001-1.1(ii) Requirement R6: The reliability objective of requiring Transmission Operators and Balancing Authorities to monitor the status of each SPS in their area and notify affected entities of any change in status is addressed in recently approved Reliability Standard TOP-001-3 and TOP-003-3. Requirements R10 and R11 of TOP-001-3 create an affirmative obligation for Transmission Operators and Balancing Authorities to monitor the status of SPS. Pursuant to TOP-003-3, Transmission Operators and Balancing Authorities must provide notifications regarding any change in Protection System status to other Transmission Operators and Balancing Authorities.

In summary, the proposed Reliability Standards represent an improvement over currently-effective PRC-001-1.1(ii) and more effectively accomplish the reliability goals of ensuring that appropriate personnel are trained on Protection Systems and that Protection System settings are appropriately studied, coordinated, and monitored. For the reasons discussed herein, NERC respectfully requests that the Commission approve the proposed Reliability Standards and NERC

Glossary definitions, and the proposed retirement of PRC-001-1.1(ii) as just, reasonable, not unduly discriminatory, or preferential, and in the public interest.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[11] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duty of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards.[12] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[13] Section 39.5(a) of the Commission's regulations requires the ERO to file for Commission approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the

11 16 U.S.C. § 824o (2012).

12 *Id.* § 824(b)(1).

13 *Id.* § 824o(d)(5).

United States, and each modification to a Reliability Standard that the ERO proposes to make effective.[14]

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory, or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA and Section 39.5(c) of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.[15]

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[16] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[17] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders.

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[14] 18 C.F.R. § 39.5(a) (2016).

[15] 16 U.S.C. § 824o(d)(2); 18 C.F.R. § 39.5(c)(1).

[16] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[17] The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

Further, a vote of stakeholders and adoption by the NERC Board is required before NERC submits the Reliability Standard to the Commission for approval.

C. Development of the Proposed Reliability Standards

As further described in Exhibit G hereto, proposed Reliability Standard PRC-027-1 and the NERC Glossary term Protection System Coordination Study were developed as part of Project 2007-06 – System Protection Coordination to replace and improve upon Requirements R3 and R4 of PRC-001-1.1(ii). On September 11, 2015, the sixth draft of proposed Reliability Standard PRC-027-1 and the definition for the new NERC Glossary term Protection System Coordination Study received the requisite approval from the registered ballot body. A final ballot for the standard and the definition concluded on October 14, 2015, with a ballot body approval of 80.94%. The NERC Board adopted the standard and definition on November 5, 2015.[18]

PER-006-1 and the revisions to the definitions of OPA and RTA were developed in the second phase of that project, Project 2007-06.2 – Phase 2 of System Protection Coordination to replace and improve upon Requirement R1 of PRC-001-1.1(ii). Project 2007-06.2 also addressed the retirement of Requirements R2, R5, and R6 of PRC-001-1.1(ii). Proposed PER-006-1, the revised definitions of OPA and RTA, and the retirement of PRC-001-1.1(ii), Requirements R2, R5, and R6 received the requisite approval from the registered ballot body on April 25, 2016. Final ballots for the standard, the definitions, and the retirements concluded on May 26, 2016, with ballot body approvals of 82.52% (PER-006-1) and 83.37% (OPA and RTA). The NERC Board adopted the proposed standard, definitions, and retirements on August 11, 2016.

[18] NERC did not immediately file the proposed PRC-027-1 with the Commission following the Board's November 2015 adoption of the standard so as to present to the Commission the retirement of PRC-001-1.1(ii) in its entirety following the adoption of PER-006-1 and the retirement of the remaining requirements in PRC-001-1.1(ii).

IV. JUSTIFICATION FOR APPROVAL

As discussed below and in Exhibit C, the proposed Reliability Standards, NERC Glossary definitions and the retirement of PRC-001-1.1(ii) satisfy the Commission's criteria in Order No. 672 and are just, reasonable, not unduly discriminatory, or preferential, and in the public interest. As noted above, the purpose of the proposed Reliability Standards and the proposed NERC Glossary definitions is to: (1) maintain the coordination of Protection Systems installed to detect and isolate Faults on BES Elements, such that those Protection Systems operate in the intended sequence during Faults; and (2) require registered entities to provide training to their relevant personnel on Protection Systems and RAS to help ensure that the BES is reliably operated. Reliability Standard PRC-001-1.1(ii) currently addresses issues related to the coordination of Protection Systems. As explained further below, NERC proposes to retire Reliability Standard PRC-001-1.1(ii) as the requirements therein are being replaced by proposed Reliability Standards PRC-027-1 and PER-006-1 and the proposed definitions, or are addressed by Reliability Standards approved by the Commission since the effective date of PRC-001-1.

The following section is organized as follows:

1) A discussion of proposed Reliability Standard PER-006-1, the revisions to the definition of OPA and RTA, and the manner in which they, along with currently-effective Reliability Standards PER-003-1 and PER-005-2, replace and improve upon Requirement R1 of PRC-001-1.1(ii).

2) A discussion of proposed Reliability Standard PRC-027-1, the new NERC Glossary term Protection System Coordination Study, and the manner in which they replace and improve upon Requirements R3 and R4 of PRC-001-1.1(ii).

3) A discussion of the manner in which Commission-approved TOP and IRO Reliability Standards replace and improve upon Requirements R2, R5 and R6 of PRC-001-1.1(ii).

4) An explanation of the manner in which Commission-approved TOP and IRO Reliability Standards resolve outstanding Commission directives related to PRC-001-1.1(ii).

5) A discussion on the enforceability of the proposed Reliability Standards.

A. PER Reliability Standards and Retirement of Requirement R1 of PRC-001-1.1(ii)

Reliability Standard PRC-001-1.1(ii), Requirement R1 provides that "[e]ach Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area." This requirement serves an important reliability objective as Protection Systems and RAS are an integral part of reliable BES operation and must be applied and operated reliably.[19] As noted above, Protection Systems help maintain reliability by detecting and isolating faulted equipment, thereby limiting the severity and spread of system disturbances, and preventing damage to protected BES Elements. Further, the functions, settings, and limitations of Protection Systems schemes are critical in establishing SOLs and IROLs. In addition, RAS help maintain BES stability, voltages, and power flows, and limit the impact of Cascading or extreme events.

When Generator Operator, Transmission Operator, and Balancing Authority personnel understand the purpose and functions of Protection System schemes applied in their area, they can operate the BES in a more reliable manner, as follows:

- When Generator Operator personnel understand the purpose and limitations of Protection System schemes, the Generator Operator better understands how those schemes affect the output of their generation facilities and, in turn, are better equipped to operate their generation facilities to maintain reliability.

- When Transmission Operator personnel are familiar with the purpose and limitations of Protection System schemes in their area, the Transmission Operator has a better understanding of the manner in which their system operates and, in turn, can more effectively operate their system within SOLs and IROLs, and identify when the reliability of the system is threatened or reduced.

- When Balancing Authority personnel are familiar with the purpose and limitations of Protection System schemes in their area, the Balancing Authority has a better understanding of the manner in which these schemes affect the maintenance of generation,

[19] The phrase "Protection System schemes" in PRC-001-1.1(ii), Requirement R1 maps to both the NERC Glossary terms "Protection Systems" and "Remedial Action Schemes." As RAS are essentially schemes comprised of Protection Systems, the phrase "Protection System schemes" would include RAS.

load and interchange balance and, in turn, can ensure that Protection Schemes are enabled when needed for reliability.

The language of PRC-001-1.1(ii), Requirement R1, however, has created some uncertainties. First, because the requirement does not specify the type of Generator Operator, Transmission Operator, or Balancing Authority personnel that must be familiar with the purpose and limitations of Protection System schemes, it is unclear to many industry stakeholders which personnel must have the requisite familiarity for the functional entity to satisfy the requirement. There is also uncertainty as to the steps an applicable entity must take to demonstrate that it has the requisite familiarity. For example, applicable entities are uncertain whether the standard requires them to conduct formal training of certain personnel whose job functions relate to or could be affected by Protection System schemes, or whether it is sufficient for the entity to have reference documents discussing the purpose and limitations of Protection System schemes that personnel may review when they deem necessary.

Due to the importance of Protection Systems to the reliable operation of the BPS, the Reliability Standards related to these systems should set clear obligations. To that end, NERC proposes to replace PRC-001-1.1(ii), Requirement R1 with new and existing formal training requirements in the PER group of Reliability Standards. Focusing on formal training requirements will help ensure that the necessary personnel are familiar with and understand the purpose and limitations of Protection System schemes while providing more precise and auditable requirements. The following sections discuss the manner in which proposed Reliability Standard PER-006-1 and currently-effective Reliability Standards PER-003-1 and PER-005-2, collectively provide for formal training requirements for Generator Operators, Transmission Operators, and Balancing Authorities on Protection Systems and RAS, consistent with the objective of PRC-001-1.1(ii), Requirement R1. Further, as discussed below, the revisions to the definitions of OPA and

RTA will also ensure that Transmission Operators, along with Reliability Coordinators, are familiar with and consider the functions and limitation of Protection Systems and RAS as they carry out their reliability functions.

1. Generator Operators

Currently-effective Reliability Standard PER-005-2, Requirement R6 and proposed Reliability Standard PER-006-1 address Generator Operator familiarity with the purpose and limitations of Protection System schemes. As discussed below, these standards provide more precise, auditable and enforceable requirements to meet the objective of Requirement R1 of PRC-001-1.1(ii) by: (1) focusing on formal training requirements; (2) clearly identifying the Generator Operator personnel that must receive training; (3) referencing both Protection Systems and RAS, instead of the undefined term "Protection System scheme;" and (4) clarifying the subject matter of the training on Protection Systems and RAS.

Reliability Standard PER-005-2, Requirement R6 and proposed PER-006-1 improve upon existing Reliability Standard PRC-001-1.1(ii) by establishing formal requirements for all relevant Generator Operator personnel on Protection Systems and RAS. Reliability Standard PER-005-2, Requirement R6, which became effective on July 1, 2016, provides that Generator Operators must use a systematic approach to develop and implement training for dispatch personnel at centrally located dispatch centers "on how their job function(s) impact the reliable operations of the BES during normal and emergency operations."[20] PER-005-2, Requirement R6 thus creates an

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[20] The specific Generator Operator personnel that must be trained using a systematic approach under PER-005-2 are "[d]ispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control." PER-005-2, Requirement R6 was specifically developed to respond to a specific FERC directive from Order Nos. 693 and 742 to include training requirements for centrally-located dispatch personnel. *Mandatory Reliability Standards for the Bulk-Power System*, 72 Fed. Reg. 16416 (2007), FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007); *System Personnel Training Reliability Standards*, Order No. 742, 133 FERC ¶ 61,159 75 Fed. Reg. 72664 (2010).

affirmative obligation for Generator Operators, using a systematic approach, to (1) identify the manner in which the job functions of centrally-located dispatch personnel could impact the reliable operations of the BES, including among other things, as it relates to the functionality of Protection System schemes, and (2) develop and implement the necessary training to help ensure that the dispatchers carry out their job functions in a manner that will not adversely impact BES reliability. If the dispatch personnel's job function can impact the reliable operation of Protection Systems and RAS, then the Generator Operator must train the dispatcher on the manner in which its job functions could impact Protection Systems and RAS.[21]

Recognizing that PER-005-2, Requirement R6 is limited to centrally-located dispatch personnel, the Project 2007-6.2 standard drafting team ("SDT") developed proposed Reliability Standard PER-006-1 to cover other Generator Operator personnel whose job functions necessitate that they be trained on the purpose and limitations of Protection System schemes. Specifically, "[p]lant personnel who are responsible for the Real-time control of a generator and receive Operating Instruction(s) from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center."[22] It is appropriate to train plant personnel with Real-time control of a generator as it is those individuals whose actions could impact the reliable operation of the BES and who, in turn, need to understand the functionality of Protection Systems and RAS and how they could affect the generation facility at which they have control.[23]

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[21] For instance, the centrally located dispatchers may need to understand the circumstances for which the functionality or limitations of a Protection System or RAS may create a risk under specific dispatch instructions.

[22] Proposed Reliability Standard PER-006-1 Applicability section 4.1.1.1.

[23] Plant personnel that do not have Real-time control include, for example, fuel handlers, electricians, machinists, or maintenance staff.

For these personnel, proposed PER-006-1 establishes a formal training requirement that that states:

> Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1 on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies) it operates.

The proposed standard represents an improvement over existing PRC-001-1.1(ii) in several key respects. First, proposed PER-006-1 specifically references Protection Systems and RAS to avoid confusion as to the scope of the phrase "Protection System schemes," which is used in PRC-001-1.1(ii). As noted above, as RAS are essentially schemes comprised of Protection Systems, the phrase "Protection System scheme" maps to both the NERC Glossary terms "Protection System" and "RAS." To avoid any confusion as to whether RAS must be the subject of training under Requirement R1 of proposed PER-006-1, the SDT specifically referenced Protection Systems and RAS.

Proposed PER-006-1 also uses the phrase "operational functionality" instead of the phrase "purpose and limitations" used in PRC-001-1(ii) to more clearly identify the objective of the training. The phrase "operational functionality" focuses the required training on (1) the manner in which Protection Systems operate and prevent damage to BES Elements, and (2) the manner in which a RAS detects pre-determined BES conditions and automatically takes corrective actions. These are the key elements for which Generator Operator personnel need be aware to reliably operate their facilities. Training on the operational functionality of Protection Systems and RAS may include, among other things, the following topics: the purpose of protective relays and RAS; zones of protection; protection communication systems (e.g., line current differential, direct transfer trip, etc.); voltage and current inputs; station dc supply associated with protective functions; resulting actions, such as tripping/closing of breakers; tripping of a generator step-up transformer, or generator ramping/tripping control functions.

Additionally, PER-006-1 uses the phrase "that affect the output of the generating Facility(ies) it operates" in lieu of the phrase "applied in its area" from PRC-001-1.1(ii). First, NERC Reliability Standards do not use the concept of a Generator Operator area as is done for Balancing Authorities and Transmission Operators. Second, in contrast to Balancing Authorities and Transmission Operators, Generator Operators are not required to monitor or study BES reliability in their area and do not have the same wide area view of BES reliability to know the precise manner in which their facility could affect the BES in Real-time. The focus of Generator Operator reliability functions under NERC's Reliability Standards is thus on the reliable operation of their generation facilities. Consistent with that reliability objective, the phrase "that affect the output of the generating Facility(ies) it operates" properly tailors the scope of training required for Generator Operators. Under proposed Reliability Standard PER-006-1, Generator Operators must identify those Protection Systems and RAS that affect the output of their generation facilities and train the applicable personnel on the operational functionality of those Protection Systems and RAS.

The proposed standard does not specify a periodicity for the required training. NERC expects applicable entities to train their plant operating personnel prior to such personnel performing any Real-time operations. NERC also expects that Generator Operators update the training to reflect any changes to the operational functionality of Protection Systems and RAS.

2. Transmission Operators and Balancing Authorities

For Transmission Operators and Balancing Authorities, the reliability goal of Requirement R1 of PRC-001-1.1(ii) is addressed by the existing certification and training requirements in the

PER group of Reliability Standards, specifically PER-003-1 and PER-005-2. As discussed below, these requirements help ensure that the relevant Transmission Operator and Balancing Authority personnel have the requisite knowledge of Protection Systems and RAS, among other things, to effectively carry out their reliability-related tasks. Further, these requirements help ensure that these personnel receive ongoing training to continue to reinforce the skills and knowledge required for those tasks. The proposed modifications to the definitions of OPA and RTA further the objective of PRC-001-1.1(ii), Requirement R1 by requiring that Transmission Operators consider the functions and limitations of Protection Systems and RAS when performing the OPAs and RTAs required under TOP Reliability Standards to determine whether there are any actual or expected SOL exceedances. These requirements are each discussed in turn, below.

i. PER-003-1 Certification Requirements

Pursuant to Reliability Standard PER-003-1, each Reliability Coordinator, Transmission Operator, and Balancing Authority must staff its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated minimum competency in the specified areas by obtaining and maintaining the relevant NERC credential. In support of NERC's mission to promote the reliability of the North American BPS, NERC administers a System Operator Certification Program to help ensure that BPS operators have a workforce of system operators that have the skills and qualifications to reliably operate the BPS.[24] The System Operator Certification Program provides the framework for operators to obtain initial certification in one of the following four NERC credentials focusing on a specific functional area of system operations:

[24] NERC maintains the required credentials for over 6,000 system operators working in system control centers across North America.

1) *Reliability Operator*, which focuses on the skills and knowledge required for Reliability Coordinator System Operators;

2) *Balancing, Interchange, and Transmission Operator*, which focusses on the skills and knowledge required for both Transmission Operator and Balancing Authority System Operators;

3) *Transmission Operator*, which focuses on the skills and knowledge required for Transmission Operator-only System Operators; and

4) *Balancing and Interchange Operator*, which focuses on the skills and knowledge required for Balancing Authority-only System Operators.

To obtain any of one these four credentials, an individual must pass the NERC System Operator Certification Exam applicable to that credential. The system operator certification exams test specific knowledge of job skills and Reliability Standards, and are designed to prepare operators to handle the BPS during normal and emergency operations.[25] Once an individual passes any of these exams, s/he must complete NERC-approved continuing education program courses and activities to maintain the certification.

The certification requirements in PER-003-1 help meet the objective of PER-001.1.1(ii), Requirement R1 by mandating that Transmission Operator and Balancing Authority System Operators demonstrate that they have the requisite knowledge about Protection Systems and RAS to maintain reliable operation in their area. Specifically, pursuant to Requirement R2 of PER-003-1, each Transmission Operator must staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in certain specified areas, including "protection and control", by obtaining

[25] NERC conducts an extensive job analysis survey of certified operators across the industry to provide the basis for the exams. The job analysis survey results in an exam content outline for each of the exams. The exam content outline is the framework used to associate tasks to exam questions. NERC contracts with psychometric consultants who assist a working group of certified system operators in the development and maintenance of each exam. The exam working group consists of subject matter experts from all regions of North America.

and maintaining valid NERC certification as a (1) Reliability Operator, (2) Balancing, Interchange and Transmission Operator, or (3) Transmission Operator.

The exams required for these certifications include, among other things, a specific focus on ensuring that such personnel can demonstrate competency in the area of protection and control.[26] The protection and control area of the exam includes the following six topics: (1) analyzing the impact of protection equipment outages on system reliability; (2) ensuring special protective systems and RAS are enabled when needed for system reliability; (3) maintaining adequate protective relaying during all phases of system restoration; (4) analyzing relay targets, fault locaters and fault recorders to determine a proper restoration plan following a system event; (5) taking action in response to alarms from special protective schemes; and (6) scheduling system telecommunications, telemetering, protection, and control equipment outages to ensure system reliability.

Similarly, Requirement R3 provides that each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in certain areas by obtaining and maintaining valid NERC certification as a (1) Reliability Operator, (2) Balancing, Interchange and Transmission Operator, or (3) Balancing and Interchange Operator. While "protection and control" is not a specific area of competency listed in Requirement R3, each of the exams required to obtain the requisite certifications include topics related to Protection Systems.

Specifically, the exams for the (1) Reliability Operator certificate and (2) Balancing, Interchange and Transmission Operator certificate are also used for Reliability Coordinator and

[26] *See*, *e.g.*, NERC's *Transmission Operator Certification Exam Content Outline 2015*, *available at* http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Transmission%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf.

Transmission Operator System Operator certification, respectively, and thus include "protection and control" as an area of specific focus. The Balancing and Interchange Operator certificate exam, which is acceptable for Balancing Authority-only System Operators and does not include "protection and control" as a specified area of focus, nevertheless includes five of the six topics related to Protection Systems and RAS that are in the other exams. Specifically, the Balancing and Interchange Operator exam includes, among others, questions related to the following topics: (1) analyzing the impact of protection equipment outages on system reliability; (2) ensuring special protective systems and RAS are enabled when needed for system reliability; (3) maintaining adequate protective relaying during all phases of system restoration; (4) taking action in response to alarms from special protective schemes; and (5) scheduling system telecommunications, telemetering, protection, and control equipment outages to ensure system reliability.[27]

ii. PER-005-2 Training Requirements

In addition to the certification requirements of PER-003-1, Reliability Standard PER-005-2 includes a number of requirements that collectively satisfy the objective of ensuring that Transmission Operators and Balancing Authorities are familiar with the purpose and limitations of Protection System schemes. First, pursuant to Requirement R1, each Transmission Operator and Balancing Authority must use a systematic approach to develop and implement a training program for its System Operators that, among other things, includes regular training on Protection Systems and RAS. Specifically, Requirement R1 requires Transmission Operators and Balancing Authorities to:

- Create a list of BES "company-specific Real-time reliability-related tasks based on a defined and documented methodology" that is updated on an annual basis (Part 1.1).

[27] *See* NERC's *Balancing and Interchange Operator Certification Exam Content Outline 2015*, *available at* http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Balancing%20and%20Interchange%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf.

- Design and develop training materials based on the BES company-specific Real-time reliability-related task list (Part 1.2).
- Deliver the training to its System Operators (Part 1.3).
- Conduct an evaluation each calendar year of its training program to identify any needed changes to the training program and implement the identified changes (Part 1.4).

As the certification exams described above indicate, the Real-time reliability-related tasks of Transmission Operator and Balancing Authority System Operators relate to the operation of Protection Systems and RAS. The training programs required under Requirement R1 must thus include training on topics related to Protection Systems and RAS. The proposed revisions to the definitions of OPA and RTA, which, as further discussed below, require Transmission Operators to consider the functions and limitations of Protection Systems and RAS when performing OPAs and RTAs, further highlight that addressing issues related to Protection Systems and RAS are part of a Transmission Operator's Real-time reliability-related tasks and, in turn, should be included in the training program under PER-005-2, Requirement R1.

Additionally, Requirement R3 of PER-005-2 provides that Transmission Operators and Balancing Authorities must verify that its System Operators are capable of performing each of the company-specific Real-time reliability-related tasks identified under Requirement R1. This requirement helps ensure that the System Operator who is engaged in tasks associated with Protection Systems and RAS are capable of performing those tasks. In verifying that capability, Transmission Operators and Balancing Authorities must confirm that the System Operator understands the functions and limitations of the relevant Protection Systems and RAS.

Requirement R4 further reinforces these capabilities by requiring each Transmission Operator and Balancing Authority that "(1) has operational authority or control over Facilities with established [IROLs], or (2) has established protection systems or operating guides to mitigate IROL violations," to provide its System Operators with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. Simulation training further enhances System Operator understanding of the relevant Protection Systems and RAS and the manner in which they impact BES operations.

Lastly, PER-005-2, Requirement R5 helps ensure that Transmission Operators and Balancing Authorities provide training to personnel who are not System Operators but have job functions that impact Real-time reliability-related tasks related to Protection Systems and RAS. Specifically, Requirement R5 provides that Transmission Operators and Balancing Authorities must "use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified" pursuant to Requirement R1.[28] As Operations Support Personnel perform OPAs and RTA in support of outage coordination and establishment of SOLs and IROLs, the required training should include material fostering an appropriate understanding of the functions and limitations of Protection Systems and RAS in their area, consistent with the objectives of PRC-001-1.1(ii), Requirement R1 and the modifications to the definition of OPA and RTA.

iii. Revised OPA and RTA Definitions

As discussed further in Exhibit E hereto, NERC also proposes modifications to the definitions of OPA and RTA to include the functions and limitations of Protection System and RAS as a required input for OPAs and RTAs. The modifications further the objective of PRC-001-1.1(ii), Requirement R1 by requiring entities to consider the functions and limitations of

[28] Operations Support Personnel are "individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time operations of the Bulk Electric System."

Protection Systems and RAS when assessing anticipated and potential conditions for next-day operations time frame (OPAs) and existing and potential operating conditions in Real-time (RTAs).

Pursuant to Commission-approved Reliability Standard TOP-002-4, Requirements R1 and R2, Transmission Operators are required to: (1) "have an [OPA] that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its [SOLs];" and (2) "have an Operating Plan(s) for next-day operations to address potential [SOL] exceedances identified as a result of its [OPA]."

The Commission approved definition of OPA is:

> An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

To ensure that the functions and limitation of Protection Systems and RAS are inputs into the OPA, NERC is proposing to modify the definition as follows:

> An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to:~~,~~ load forecasts; generation output levels; Interchange; known Protection System and ~~Special Protection System~~ Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)[29]

[29] NERC proposes to replace the term "Special Protection System" with "Remedial Action Scheme" to reflect the transition across NERC standards to using RAS. *See N. Am. Elec. Reliability Corp.*, Docket No. RD16-5-000 (Jun. 23, 2016) (unpublished letter order).

Similarly, under Commission-approved Reliability Standard TOP-001-3, Requirements R13 and R14, each Transmission Operator is required to: (1) perform a RTA at least once every 30 minutes; and (2) initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or RTA. The current definition of RTA is:

> An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation; Transmission outages, generator outages, Interchange; Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

As with the modifications to the OPA definition, to ensure that the functions and limitation of Protection Systems and RAS are inputs into the RTA, NERC is proposing to modify the definition as follows:

> An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load; generation output levels; known Protection System and ~~Special Protection System~~ Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Interchange; Facility Ratings; and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

3. Reliability Coordinators

Although PRC-001.1.1(ii), Requirement R1 does not apply to Reliability Coordinators, it is also important for Reliability Coordinator personnel to understand the functions and limitations of Protection Systems and RAS and consider that information when conducting OPAs and RTAs. The Reliability Coordinator has a central role in maintaining BES reliability, particularly with respect to helping to ensure that the BES is operated within SOLs and IROLs. As such, an understanding of Protection Systems and RAS is vital to the functional obligations of a Reliability Coordinator.

Accordingly, as is the case for Transmission Operators and Balancing Authorities, NERC's currently-approved Reliability Standards require the following to help ensure that Reliability Coordinator personnel have the requisite understanding of Protection Systems and RAS:

- Reliability Coordinators must staff their Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated competency in the area of "protection and control," among others, through the NERC System Operator Certification Program (PER-003-1, Requirement R1).

- Reliability Coordinators must train their System Operators, using a systematic approach, on their Real-time reliability related tasks, which may include tasks related to Protection Systems and RAS (PER-005-2, Requirement R1).

- Reliability Coordinators must verify that their System Operators are capable of performing each of the company-specific Real-time reliability-related tasks identified under PER-005-2, Requirement R1 (PER-005-2, Requirement R3).

- Reliability Coordinators that have (1) operational authority or control over Facilities with established IROLs, or (2) established protection systems or operating guides to mitigate IROL violations, must provide their System Operators emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES (PER-005-2, Requirement R4).

- Reliability Coordinators must provide training, using a systematic approach, to Operations Support Personnel on how their job function(s), including those related to Protection Systems and RAS, impact those BES company-specific Real-time reliability-related tasks identified pursuant to PER-005-2, Requirement R1.

In addition to these Commission-approved certification and training requirements, the modifications to the definitions of OPA and RTA require Reliability Coordinators to consider the functions and limitations of Protection Systems and RAS when conducting OPAs and RTAs to assess whether there are any actual or expected SOL or IROL exceedances, pursuant to Reliability Standard IRO-008-2, Requirements R1, R4 and R5. As the modifications to the definitions of OPA and RTA also apply to the Reliability Coordinator, they serve to enhance the manner in which the reliability objective of PRC-001-1.1(ii), Requirement R1 is met in NERC's Reliability Standards.

B. PRC-027-1 and Retirement of Requirements R3 and R4 of PRC-001-1.1(ii)

Proposed Reliability Standard PRC-027-1 is designed to improve upon and replace Requirements R3 and R4 of PRC-001-1.1(ii) in addressing the coordination of Protection Systems installed to detect and isolate Faults on the BES, such that those Protection Systems operate in their intended sequence during Faults. As noted above, coordinated Protection Systems enhance reliability by reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. Specifically, when Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage.

Proposed Reliability Standard PRC-027-1 provides a clear set of Requirements that obligate entities to (1) implement a process for establishing and coordinating new or revised Protection System settings, and (2) periodically study Protection System settings that could be affected by incremental changes in Fault current to ensure the Protection Systems continue to operate in their intended sequence. Specifically, proposed PRC-027-1 consists of the following three requirements, each of which is discussed in greater detail below:

- Requirement R1 mandates that each Transmission Owner, Generator Owner, and Distribution Provider establish a process for developing new and revised Protection System settings for BES Elements to operate in the intended sequence during Faults. The process must include provisions for coordinating those settings with owners of electrically joined facilities.

- Requirement R2 mandates that, for each BES Element with a Protection System that could be affected by changes in Fault current, applicable entities must, every six years, determine whether the Protection System settings continue to be appropriate by: (1) performing a Protection System Coordination Study; (2) first evaluating whether there were any changes in Fault current that could affect the coordination of Protection System and, if so, performing a Protection System Coordination Study; or (3) a combination of the above two options. The proposed definition for the term Protection System Coordination Study is "[a]n analysis to determine whether Protection Systems operate in the intended sequence during Faults."

- Requirement R3 requires applicable entities to implement the process established according to Requirement R1 for developing new or revised Protection System settings.

Collectively, these Requirements help ensure that Protection Systems are installed in a coordinated manner and operate in the intended sequence to isolate Faults on the BES.

Proposed Reliability PRC-027-1 improves upon Requirements R3 and R4 of PRC-001-1.1(ii) by:

- Assigning the responsibility for performing coordination responsibilities to the owners of the Protection Systems whose functional obligations include setting, coordinating, and maintaining Protection Systems.
- Clarifying that proposed PRC-027-1 pertains to the coordination of Protection Systems associated with Fault clearing.
- Clarifying that the scope of the proposed standard applies to any Protection System installed to detect and isolate Faults on BES Elements, regardless of location (i.e., internal lines as well as tie-lines).
- Adding a Requirement that applicable entities establish and use a process to develop settings for their BES Protection Systems that must contain certain specified attributes.
- Adding a Requirement that applicable entities periodically perform Protection System Coordination Studies and/or review Fault current values for existing Protection Systems applied on BES Elements that are identified as being affected by changes in Fault current to determine whether the settings continue to be appropriate.

The following is a discussion of the applicability of the proposed standard and an analysis of each Requirement.

1. Applicability

Proposed Reliability Standard PRC-027-1 is applicable to Transmission Owners, Generator Owners, and Distribution Providers as these are the entities that own and install Protection Systems for the purpose of detecting Faults in the BES and have the functional obligations to maintain those Protection Systems. Transmission Owners own the largest number of Protection Systems installed for the purpose of detecting Faults on the BES. Generator Owners also have Protection Systems installed for the purpose of detecting Faults on the BES and it is important that those Protection Systems are coordinated with Protection Systems owned by Transmission Owners to ensure that generation Facilities do not become disconnected from the BES unnecessarily. Functions such as impedance reaches, overcurrent pickups, and time delays need to be evaluated for coordination. Lastly, Distribution Providers may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of the Distribution Provider.

As the owners of the Protection Systems, these entities should have the obligation to implement a coordinated process for developing new and revised Protection System settings and reviewing those setting on a periodic basis. Under the NERC Functional Model, the reliability tasks related to Transmission, Distribution, and Generation Ownership include design and maintenance of Protection Systems.[30] These functions include developing Protection System settings, evaluating Protection System operations, and identifying Protection System Misoperations. As part of designing the Protection Systems, these entities must coordinate with their neighbors to ensure the Protection System operates in the intended sequence during Faults. In contrast, Transmission Operators and Generator Operators are only concerned with Protection Systems after they are placed in service.

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30 The Functional Model provides (at p. 44) that Transmission Ownership includes the following task: "Design and authorize maintenance of transmission protective relaying systems and Special Protection Systems." For Distribution, the Functional Model (at p. 46) lists the following as a task: "Design and maintain protective relaying systems, under-frequency load shedding systems, under-voltage load shedding systems, and Special Protection Systems that interface with the transmission system." Lastly, the Functional Model (at p. 50), includes the following task for Generation Ownership: "Design and authorize maintenance of generation plant protective relaying systems, protective relaying systems on the transmission lines connecting the generation plant to the transmission system, and Special Protection Systems." The Functional Model is available at: http://www.nerc.com/pa/Stand/Functional%20Model%20Archive%201/Functional_Model_V5_Final_2009Dec1.pdf

In addition to clarifying the functional entities responsible for performing coordination responsibilities, proposed Reliability Standard PRC-027-1 also clarifies that the standard only applies to coordination of Protection Systems associated with Fault clearing. Aspects of protection coordination other than Fault coordination are addressed by other Reliability Standards. Specifically, other protection issues, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following Reliability Standards:

- Underfrequency Load shedding programs are addressed in PRC-006-2.
- Undervoltage Load shedding programs are addressed in PRC-010-2.
- Generator performance during declined frequency and voltage excursions is addressed in PRC-024-2.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-2.
- Transmission relay loadability is addressed in PRC-023-3.
- Generator relay loadability is addressed in PRC-025-1.
- Protective relay response during stable power swings is addressed in PRC-026-1.
- Protection System Misoperations (including those caused by coordination issues) are addressed in PRC-004-5i.

Additionally, whereas Requirement R4 of PRC-001-1.1(ii) is limited to the coordination of Protection Systems on "major transmission lines," the Requirements of PRC-027-1 apply to any Protection System installed to detect and isolate Faults on BES Elements, regardless of location, size, or whether they are tie-lines or internal lines. Eliminating the phrase "major transmission lines" also avoids the ambiguities involved in determining which lines are "major."

2. <u>Requirement R1</u>

Requirement R1 mandates that each Transmission Owner, Generator Owner, and Distribution Provider establish a process for developing new and revised Protection System settings for BES Elements, such that those Protection Systems operate in the intended sequence during Faults (i.e., are properly coordinated). The process must include provisions designed to ensure that the settings are accurate and coordinated with owners of electrically joined facilities. Specifically, Requirement R1 provides:

> **R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include:
>
> **1.1.** A review and update of short-circuit model data for the BES Elements under study.
>
> **1.2.** A review of the developed Protection System settings.
>
> **1.3.** For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:
>
> **1.3.1.** Provide the proposed Protection System settings to the owner(s) of the electrically joined Facilities.
>
> **1.3.2.** Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.
>
> **1.3.3.** Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.
>
> **1.3.4.** Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure.

This Requirement applies to changes to Protection System settings for any BES Element. Although the coordination of some Protection Systems may seem unnecessary, such as for a line that is protected solely by dual current differential relays, backup Protection Systems that are enabled to operate based on current or apparent impedance with some definite or inverse time delay must be coordinated with other Protection Systems of the BES Element such that tripping does not unnecessarily occur for Faults outside of the differential zone.

The following is a discussion of each Part of Requirement R1:

Part 1.1 helps ensure that applicable entities develop any new or revised Protection System settings using accurate and updated data by requiring them to review and update short-circuit model data for the BES Element(s) under study.[31] A short-circuit study is an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical Fault. These studies form the basis for the development of Protection System settings as they provide the necessary Fault currents used by protection engineers to develop Protection System settings. Requiring a review and, if necessary, an update of short-circuit model data is thus necessary to ensure that the information that forms the basis of the development of Protection System settings is accurate and reflects the physical power system. The review of short-circle model data would include a review of:

- applicable BES line, transformer, and generator impedances and Fault currents;
- the network model to confirm the network in the study accurately reflects the configuration of the actual System, or how the System will be configured when the proposed relay settings are installed; and
- where applicable, interconnected Transmission Owner, Generator Owner, and Distribution Provider information.

Part 1.2 further supports the development of accurate Protection System settings by requiring applicable entities to institute a systematic process for verifying that the Protection System settings are correct (i.e., that they meet applicable technical criteria, as defined by the entity). A review of the Protection System settings prior to implementation reduces the possibility

[31] Although Generator Owners and Distribution Providers may not have or maintain short-circuit models, NERC expects these entities to obtain the short-circuit model data from their Transmission Planners, Planning Coordinators, or Transmission Owners.

of introducing human error. Examples of reviews include peer reviews, automated checking programs, and other entity-developed review procedures designed to verify the accuracy of the settings.

Part 1.3 addresses the coordination of Protection System settings between neighboring entities for BES Elements that electrically join Facilities owned by separate functional entities.[32] Communication among neighboring entities is essential for identifying and resolving coordination issues prior to implementation of any new or revised Protection System settings. Part 1.3 creates the following obligations:

- Under Part 1.3.1, applicable entities proposing to change any Protection System setting for BES Elements that electrically join facilities owned by separate functional entities must include in their process provisions for providing proposed Protection System settings to their neighboring entities so as to allow those entities an opportunity to review those settings and determine whether there are any coordination issues.

- Under Part 1.3.2, applicable entities must include in their process provisions for responding to neighboring entities that provided them proposed Protection System setting under Part 1.3.1 by identifying any coordination issues or affirming that no such issues are present. These provisions ensure that the proposed settings are reviewed and that the initiating entity receives a response indicating whether there are any coordination issues to address prior to implementation.

- Under Part 1.3.3, applicable entities must include provisions in their process for verifying that any identified coordination issues are resolved with the neighboring entity prior to implementation, thereby minimizing any potential impact to BES reliability.[33]

[32] The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

[33] There could be instances where coordination issues are identified and the entities agree not to mitigate all of the issues based on engineering judgment. Further, coordination issues identified during a project may not be immediately resolved if the resolution involves additional system modifications not identified in the initial project scope. There could also be situations where protection philosophies differ between entities, but the entities can agree that these differences do not create coordination issues.

- Under Part 1.3.4, applicable entities must have provisions for communicating with neighboring entities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure. This Part recognizes that there may be instances under which changes to Protection Systems need to be made without the opportunity to coordinate with neighboring entities in the timeframe contemplated under Parts 1.3.1 through 1.3.3. Nevertheless, those changes need to be coordinated with other entities to address any issues going forward.

3. Requirement R2

The reliability objective of Requirement R2 is to mitigate risks associated with the impact of changes in Fault current on Protection Systems installed to detect and isolate Faults on the BES. Over time, the accumulation of incremental changes in Fault current could affect the coordination of Protection Systems (i.e., the performance of the Protection System during Faults). Entities should thus be required to determine whether there were any changes in Fault current that affected the coordination of Protection Systems and, if so, adjust the settings as necessary to ensure the Protection System continues to operate in the intended sequence during Faults.

To that end, Requirement R2 mandates that, for BES Elements with Protection Systems that could be affected by changes in Fault current, applicable entities must, every six years, determine whether the Protection System settings continue to be appropriate by either: (1) performing a Protection System Coordination Study for each applicable BES Element to determine whether the Protection Systems continue to operate in the intended sequence during Faults; or (2) first evaluating whether there were any changes in Fault current at each BES Element that could affect the coordination of Protection Systems and, if so, performing a Protection System Coordination Study for that BES Element; or (3) using a combination of the above options to conduct a review at each applicable BES Element. Specifically, Requirement R2 provides as follows:

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A:

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six-calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the BES Element is connected, all in a time interval not to exceed six-calendar years; or
- Option 3: Use a combination of the above.

The components of Requirement R2 are discussed further below.

i. BES Element with Protection System Functions Identified in Attachment A

As noted above, the purpose of Requirement R2 is to periodically review Protection Systems that could be affected by changes in Fault current to determine whether the settings continue to be appropriate. Attachment 1 lists those Protection System functions that use current in their measurement to initiate tripping of circuit breakers and, as a result, changes in the magnitude of available Fault current could impact the coordination of these functions. Attachment A provides:

> The following Protection System functions are applicable to Requirement R2 if: (1) available Fault current levels are used to develop the settings for those Protection System functions; and (2) those Protection System functions require coordination with other Protection Systems.
>
> 21 – Distance if:
>
> - infeed is used in determining reach (phase and ground distance), or
> - zero-sequence mutual coupling is used in determining reach (ground distance).
>
> 50 – Instantaneous overcurrent
>
> 51 – AC inverse time overcurrent

67 – AC directional overcurrent if used in a non-communication-aided protection scheme

The numerical identifiers in Attachment A represent general device functions according to *ANSI/IEEE Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*. Examples of functions not included in Attachment A are differential relays and Fault detectors as they do not meet the above criteria.[34] Under Requirement R2, if an applicable entity has any BES Elements with the Protection System functions listed in Attachment A, the entity must perform a review of the Protection Systems for that BES Element every six calendar years to determine whether Fault currents have affected the coordination of the Protection System and the settings need to be changed. Requirement R2, however, provides entities flexibility in the manner in which it conducts its review of those Protection Systems by providing three options, as discussed below.

ii. Option 1 – Performing Protection System Coordination Studies

To satisfy its obligation under Requirement R2, an applicable entity may choose to perform a full Protection System Coordination Study every six calendar years for each of its applicable BES Elements. The proposed definition for the new NERC Glossary term Protection System Coordination Study is "[a]n analysis to determine whether Protection Systems operate in the intended sequence during Faults." If the results of the Protection System Coordination Study reveal that the Protection System requires revised settings to operate in its intended sequence during faults, the applicable entity would then initiate its process established pursuant to Requirement R1 to change the settings for those Protection Systems in accordance with the Protection System Coordination Study.

34 For additional information regarding the Protection System functions listed in Attachment A, see the Supplemental Material section of the proposed standard.

In performing a Protection System Coordination Study, applicable entities would evaluate current pickup levels, timing characteristics, impedance characteristics, and fault detector levels of relays to seek the best coordination possible of Protection Systems providing primary and backup protection of BPS Elements.

iii. Option 2 – Comparison of Fault Current Values

Under Option 2, instead of immediately conducting Protection System Coordination Studies for each of its BES Elements with a Protection System function listed in Attachment A, an entity may first choose to compare present Fault current values at each of those BES Element to an established Fault current baseline to determine whether a Protection System Coordination Study is in fact necessary. This option provides entities the flexibility to determine whether there were any changes in Fault current at the BES Element that could affect Protection System coordination prior to expending its resources to perform a full Protection System Coordination Study.

Requirement R2 establishes a Fault current deviation of 15% or greater from a baseline established from the most recent Protection System Coordination Study as the threshold for determining whether a Protection System Coordination Study is necessary.[35] Specifically, if the Fault current comparison for a BES Element indicates a deviation of less than 15% from the established baseline, the applicable entity is not required to conduct a full Protection System Coordination Study for that BES Element. If, however, the Fault current comparison indicates a 15% percent or greater deviation on a BES Element, the applicable entity is then required to conduct a full Protection System Coordination Study for that BES Element to determine whether

[35] As discussed below, entities seeking to use Option 2 for the initial performance of this Requirement must establish a baseline by the effective date of the standard based on short-circuit studies.

the Protection Systems for that BES Element continue to operate in the intended sequence during Faults.

NERC proposes a 15% deviation threshold for determining whether a Protection System Coordination Study is required under Option 2 based on generally-accepted margins for setting Protection Systems in which incremental Fault current changes would not interfere with coordination. Accepted engineering practices require entities to consider proper margins while setting relays. Those margins are based on measurement errors, possible errors in fault studies, or unknown system configuration changes that can occur during system disturbances or short term operating conditions. Margins are used to help ensure that the Protection Systems operate as designed during any Fault condition and that relatively small (up to 15%) changes in Fault current do not interfere with that coordination. The 15% maximum deviation provides an entity with latitude, however, to choose a Fault current deviation threshold that is less than 15% to better match its protection philosophy, or other business considerations without creating undue risk to reliability.

If there is a Fault current deviation of 15% or greater and the results of the subsequent Protection System Coordination Study reveal that a Protection System requires revised settings to operate in its intended sequence during faults, the applicable entity would then initiate its process established pursuant to Requirement R1 to change the settings for those Protection Systems in accordance with the Protection System Coordination Study. As with Option 1, the time interval for conducting the Fault current comparison and any subsequent Protection System Coordination Study is six calendar years.

The Fault current values used in the comparison, whether three-phase or phase-to-ground Fault currents, should be determined with all generation in service and all transmission BES

Elements in their normal operating state. Further, the Fault current baseline values used as a point of reference for the Fault current comparisons can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators, or Transmission Owners. As described in the footnote 1 of the proposed standards, Fault current baselines may be established for BES generating resources at the generator, the BES aggregation point for dispersed power producing resources, or at the common point of connection at 100 kV or above.

With respect to the timing for establishing the Fault current baselines, footnote 1 in the proposed standard provides that an entity that elects to use Option 2 for its initial performance of this Requirement must establish its baseline by the effective date of the standard and update it each time it performs a Protection System Coordination Study. If an initial baseline was not established by the effective date of this Reliability Standard because the applicable entity chose Option 1 or installed a new BES Element, the entity may establish the baseline upon performing a Protection System Coordination Study. The baseline values at each bus to which a BES Element is connected are updated whenever a new Protection System Coordination Study is performed for the subject Protection System.

The following is a hypothetical example of how Option 2 would work in practice for a single BES Element: By the effective date of PRC-027-1, Entity X established an initial Fault current baseline of 10,000 amps at the bus to which the BES Element under study is connected. Consistent with Option 2, within six years of the effective date, Entity X performed a short-circuit review to determine the present Fault current value at the bus. The short-circuit review indicated that the Fault current increased to 11,250 amps, a 12.5% deviation. As the deviation was less than 15%, no Protection System Coordination Study was required for that BES Element. As such, no further action was required and Entity X satisfied its obligations under Requirement R2 for that first six-year interval.

As required by Requirement R2, six years later Entity X performed another short-circuit review to determine the present Fault current value at the bus. The baseline value for this Fault current comparison remains at 10,000 amps because Entity X did not perform a Protection System Coordination Study as a result of the initial comparison and the baseline was not reset. The results of this second Fault current comparison indicated that the Fault current increased to 11,500 (a 15% deviation). To comply with Requirement R2, Entity X must now perform a Protection System Coordination Study, also to be completed within that six-year interval, and a new baseline of 11,500 amps would be established. If the Protection System Coordination Study indicates a need to modify the Protection System settings to ensure that the Protection System operates in the intended sequence, Entity X would use its process developed under Requirement R1 to effectuate those changes. If the Protection System Coordination Study does not indicate that setting changes are necessary despite the 15% deviation, Entity X is not required to take any further action (although its Fault current baseline is reset to 11,500 amps for future comparisons).[36]

iv. Option 3 – Use Combination of Options 1 and 2

Option 3 provides entities the flexibility to use Option 1 at some BES Elements and Option 2 at other BES Elements based on the needs of its system. As Protection Systems at certain BES Elements are more susceptible to Fault current changes than others, applicable entities should have the latitude to choose between Option 1 and Option 2 for each BES Element. Where a BES Element is more susceptible to Fault current changes, the applicable entity may choose to bypass

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[36] Note that if, as a result of the first Fault current comparison, the entity decided to perform a Protection System Coordination Study even though there was only a 12.5% deviation and the results of the study indicate that the settings still meet the setting criteria of the entity, then no settings changes are required but the baseline Fault current would be updated to 11, 250 amps.

a Fault comparison (Option 2) and proceed straight to a Protection System Coordination Study (Option 1). In contrast, for BES Elements less susceptible to Fault current changes, the entity may choose Option 2 to do a Fault current comparison and potentially avoid the more resource intensive Protection System Coordination Study. An entity may, for example, choose Option 1 for all of its Facilities operated above 300 kV, while choosing to use Option 2 for its Facilities operated below 300 kV. No matter which option the entity chooses for each of its BES Elements, the entire cycle must be completed every six calendar years.

v. Six-Year Time Interval

NERC proposes a maximum of six-year intervals to perform the review under Requirement R2 so as to balance the resources required to perform Protection System Coordination Studies and the potential reliability impacts created by incremental changes of Fault current over time.[37] Performing Protection System Coordination Studies is a resource intensive activity. These studies require engineers to review Protection Systems at a number of substations to evaluate the coordination between the Protection Systems. This review includes performing fault simulations, creating impedance plots with relay characteristics, and time-overcurrent curve reviews where little or no change may have occurred during the six-year interval. For entities with many BES Elements with Protection System functions listed in Attachment A, significant time and personnel must be devoted to conducting Protection Systems Coordination Studies. To require entities to perform the Protection System Coordination Studies on shorter intervals may be overly burdensome without any additional reliability benefit.

NERC event analysis data supports the six-year intervals. Specifically, NERC reviewed its events analysis data from 2012-2015 to determine the number of instances in which Protection

[37] Entities may choose to do the review in shorter intervals.

System coordination issues led to an event on the BES.[38] During 2012-2015, the number of events reported through the NERC Event Analysis process that had, as part of the event, more than one Misoperation due to incorrect settings is as follows:

- 2012 - three events out of a total of 45 Misoperation events (115 total qualified events)
- 2013 - five events out of a total of 34 Misoperation events (140 total qualified events)
- 2014 - four events out of a total of 34 Misoperation events (171 total qualified events)
- 2015 - five events out of a total of 38 Misoperation events (148 total qualified events)

This data shows that Protection System coordination is not a significant issue on the BES in terms of number of events. From 2012 through 2015, only 11% of Misoperation events (17 events out of 151) and only 2.9% of total events (17 out of 574) involved Protection System coordination issues. Of the 17 events involving coordination issues, five were inter-company and 12 intra-company.[39] Given this data, the burden of requiring entities perform Protection System Coordination Studies at a time interval shorter than six years outweighs the reliability benefit of doing so.

As noted above, Requirement R2 is designed to capture incremental Fault changes that accumulate over time and could affect the coordination of Protection Systems eventually. Any changes to BPS Elements that require changes to Protection System settings will be addressed through the Requirement R1 process and implemented pursuant to Requirement R3. As such, significant accrued Fault current changes will not be likely without some evaluation due to the system changes. Requirement R2 provides assurance that entities do confirm coordination

[38] A coordination event was defined as an event that had more than one Protection System Misoperation. An event resulting from only one Misoperation is not a failure of coordination, but an isolated setting issue.

[39] In total, only 12 events (out of 151 Misoperation events, or 7.9%) were found to be internal to an entity. Overall, that is 12 events out of 574 total events reported to Events Analysis, which is 2.1% of all events.

periodically where no change to a BES Element would have otherwise addressed changes to Protection Systems due to incremental Fault current changes.

4. Requirement R3

The purpose of Requirement R3 is to require applicable entities to use the process they developed under Requirement R1 for the development of any new or revised Protection System settings for BES Elements, whether as a result of a Protection System Coordination Study performed under Requirement R2 or the installation of a new BES Element with Protection Systems. Requirement R3 provides:

> **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

As discussed above, using the Requirement R1 process helps ensures a consistent approach to the development of accurate Protection System settings, decreases the possibility of introducing errors, and increases the likelihood of maintaining a coordinated Protection System.

C. Retirement of Requirements R2, R5 and R6 of PRC-001-1.1(ii)

Consistent with Commission orders to eliminate redundancies in NERC's Reliability Standards,[40] NERC is proposing to retire the remaining Requirements in PRC-001-1.1(ii) – Requirements R2, R5, and R6 – as the reliability objectives of these Requirements are addressed by the revised TOP/IRO Reliability Standards approved in Order No. 817.[41] While NERC did not specifically intend on addressing issues related to PRC-001-1.1(ii) when revising the TOP/IRO

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[40] *See Order Accepting with Conditions the Electric Reliability Organization's Petition Requesting Approval of New Enforcement Mechanisms and Requiring Compliance Filing*, 138 FERC ¶ 61,193 at P 81 (2012); *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147, 78 Fed. Reg. 78424 (2013).

[41] In Order No. 817, the Commission approved nine revised TOP/IRO Reliability Standards – IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, IRO-017-1, TOP-001-3, TOP-002-4, and TOP-003-3. *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 80 Fed. Reg. 73977 (2015).

Reliability Standards, those revisions created certain redundancies with Requirements R2, R5, and R6 of PRC-001-1.1(ii). As such, these Requirements should be retired. The following is a discussion of the manner in which Commission-approved Reliability Standards address Requirements R2, R5, and R6 of PRC-001-1.1(ii).

1. PRC-001-1.1(ii), Requirement R2

The purpose of Reliability Standard PRC-001-1.1(ii), Requirement R2 is to require that, in the event of protective relay or equipment failures that reduce system reliability, Transmission Operators and Generator Operators: (1) notify relevant functional entities of such failures so that the relevant entities can act accordingly to maintain reliability; and (2) take timely corrective action to return the system to a stable state. Specifically, Requirement R2 provides:

> **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
>
> > **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
> >
> > **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

Requirements in recently approved Reliability Standards IRO-001-4, IRO-008-2, IRO-010-2, TOP-001-3, and TOP-003-3, however, obviate the need for Requirement R2 of PRC-001-1.1(ii). These TOP/IRO Reliability Standards address both the notification and corrective action components of PRC-001-1.1(ii), Requirement R2, as follows.

Notification of Protective Relay and Equipment Failures: The data specification Requirements in Reliability Standards TOP-003-3 and IRO-010-2 replace and improve upon the notification requirements in PRC-001-1.1(ii), Requirement R2, as discussed below. Reliability

Standards TOP-003-3 and IRO-010-2 establish Requirements for the provision of information and data needed by Transmission Operators, Balancing Authorities, and Reliability Coordinators for reliable operations. Under those standards, the information and data that applicable functional entities must provide to Transmission Operators, Balancing Authorities, and Reliability Coordinators includes, among other things, "notification of current Protection System and [SPS] status or degradation that impacts System reliability." Such notifications would include failures of protective relays or equipment as such failures would impact the status and be considered a degradation of Protection Systems and SPS.[42] These data specification standards are each discussed in turn, below.

Reliability Standard TOP-003-3 provides a mechanism for Transmission Operators and Balancing Authorities to obtain the data needed to fulfill their operational and planning responsibilities. TOP-003-3 consists of the following five Requirements:

- *Requirements R1 and R2* requires each Transmission Operator and Balancing Authority to maintain a documented specification for the data necessary for the Transmission Operator to perform its OPAs, Real-time monitoring, and RTAs, and for the Balancing Authority to perform its analysis functions and Real-time monitoring. The data specification must include, but is not limited to: (i) a list of data and information needed to support these analyses, monitoring, and assessments; (ii) provisions for the notification of current Protection System and Special Protection System status or degradation that impacts System reliability; (iii) a periodicity for providing data; and (iv) the deadline by which the respondent is to provide the indicated data.

- *Requirements R3 and R4* require each Transmission Operator (Requirement R3) and Balancing Authority (Requirement R4) to distribute its data specification to the entities that have the necessary data.

- *Requirement R5* requires each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification pursuant to Requirement R3 or R4 to satisfy the obligations of the documented data specification using: (i) a mutually agreeable format;

42 The "equipment" referenced in PRC-001-1.1(ii), Requirement R2 refer, among other things, to the components of a Protection System, such as the voltage and current sensing devices providing inputs to protective relays or the Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

(ii) a mutually agreeable process for resolving data conflicts; and (iii) a mutually agreeable security protocol.

Similarly, Reliability Standard IRO-010-2 provides a mechanism for the Reliability Coordinator to obtain the information and data it needs for reliable operations and to help prevent instability, uncontrolled separation, or Cascading outages. IRO-010-2 consists of the following three requirements:

- Requirement R1 provides that the Reliability Coordinator must maintain a documented specification for the data necessary for it to perform its OPAs, Real-time monitoring, and RTAs. The data specification must include: (i) a list of data and information necessary to support its performance of OPAs, Real-time monitoring, and RTAs, including non-Bulk Electric System data and external network data; (ii) provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability; (iii) a periodicity for providing data; and (iv) the deadline by which the respondent is to provide the indicated data.

- Requirement R2 provides that the Reliability Coordinator must distribute its data specification to entities that have the required data.

- Requirement R3 provides that each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification must satisfy the obligations of the documented specifications using a mutually-agreeable format, process for resolving data conflicts, and security protocol.

The notification obligations in Requirement R2 of PRC-001.1(ii) is thus subsumed in the data specification requirements in Reliability Standards TOP-003-3 and IRO-010-2. For Transmission Operators, Balancing Authorities and Reliability Coordinators to perform their respective analyses, monitoring, and assessment responsibilities under the TOP/IRO Reliability Standards,[43] they must receive Protection System and SPS data from Generator Operators and Transmission Operators, among others. For example, to perform an OPA or RTA, the Transmission Operator and Reliability Coordinator must, by definition, consider the status and degradation of Protection Systems and SPS/RAS such as any protective relay or equipment

[43] *See* TOP-001-3, TOP-002-4, IRO-001-4, IRO-002-4, and IRO-008-3.

failures. Comparably, for a Balancing Authority to satisfy its obligations under TOP-001-3, Requirement R11 to "monitor its Balancing Authority Area, including the status of [SPS] that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency," the Balancing Authority must be aware of the status and degradation of Protection Systems and SPS. To that end, TOP-003-3 and IRO-010-2 specifically require Transmission Operators, Balancing Authorities, and Reliability Coordinators to obtain notifications on the status and degradation of Protection Systems and SPS from, among others, Generator Operators and other Transmission Operators, as is currently required under PRC-001-1.1(ii), Requirement R2. Accordingly, if there is any failure of a protective relay or other components of a Protection System, Transmission Operators, Balancing Authorities, and Reliability Coordinators will be notified.

Reliability Standards TOP-003-3 and IRO-010-2 improve upon PRC-001-1.1(ii), Requirement R2 by clarifying the timing of such notifications.[44] PRC-001-1.1(ii) does not include any time period associated with the notification, making it difficult for entities to know when to provide the notifications from a reliability perspective and for the ERO to measure compliance with the notification requirement. In contrast, TOP-003-3 and IRO-010-2 require the Transmission Operator, Balancing Authority, and Reliability Coordinator to set (i) the periodicity for providing data, and (ii) the deadline for respondents to provide the indicated data. Applicable entities would thus have certainty as to when the notifications must be provided and the ERO would be able to determine whether the notification was provided in a timely manner.

[44] In Order No. 693, the Commission directed NERC to determine the appropriate timeframe for the notifications, as discussed further below. Order No. 693 at P 1445.

Providing Transmission Operators, Balancing Authorities, and Reliability Coordinators the authority to set the deadlines for providing the various data helps ensure that required notifications are provided within a timeframe designed to maintain reliable operations. Specifically, Transmission Operators, Balancing Authorities, and Reliability Coordinators must establish the periodicity and deadlines in a data specifications to allow those entities to perform their functional obligations specified in NERC's Reliability Standards. If certain data is needed to perform an RTA, for instance, it must be provided every 30 minutes as Reliability Coordinators and Transmission Operators must perform RTAs every 30 minutes.[45] As RTAs, by definition, require Reliability Coordinators and Transmission Operators to consider the status and degradation of Protection Systems and SPS in assessing current operating conditions every 30 minutes, NERC expects that they would require entities to provide notification of protective relay or equipment failures within 30 minutes from the time the failure is discovered, if not sooner, and the Reliability Coordinator and Transmission Operator will include that information in its next RTA.

Corrective Action: Commission-approved Reliability Standards TOP-001-3 and IRO-001-4 more clearly address the reliability objective in PRC-001-1.1(ii), Requirement R2 of requiring Transmission Operators and Generator Operators to take corrective action to address protective relay and equipment failures that reduce system reliability. Pursuant to Reliability Standards TOP-001-3, Requirements R1 and R2, and IRO-001-4, Requirement R1, each Transmission Operator, Balancing Authority, and Reliability Coordinator must "act to maintain the reliability of its [area] via direct actions or by issuing Operating Instructions."[46] Under these Requirements, if there is an event on the BES that reduces (or threatens to reduce) system reliability, such as protective

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45 *See* TOP-001-3, Requirement R13, IRO-008-2, Requirement R4.

46 IRO-001-4, Requirement R1 uses the word "address," not "maintain," where TOP-001-3, Requirements R1 and R2 use the word "maintain."

relay or equipment failures, Transmission Operators, Balancing Authorities, and Reliability Coordinators have an affirmative obligation to take corrective action to maintain reliability, whether by their own actions or by directing the actions of others through the issuance of an Operating Instruction.[47] As provided in TOP-001-3, Requirements R3-R6, and IRO-001-4, Requirements R2 and R3, any functional entity, including a Generator Operator or another Transmission Operator, that is the subject of such an Operating Instruction must: (1) comply with the Operating Instruction, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements; or (2) inform the entity that issued the Operating Instruction that it cannot comply with an Operating Instruction.

The affirmative requirements for Transmission Operators, Balancing Authorities, and Reliability Coordinators to act to maintain reliability in their area and issue Operating Instructions, when necessary, and for entities to comply with any Operating Instructions eliminate the need for a separate obligation such as that in PRC-001.1(ii), Requirement R2 for Generator Operators and Transmission Operators to take corrective action to address protective relay and equipment failures. Under the data specification requirements in Reliability Standards TOP-003-3 and IRO-010-2, if a Generator Operator or Transmission Operators notifies a Balancing Authority, Reliability Coordinator, or another Transmission Operator of a change in status or degradation of a Protection System or RAS (including protective relay or equipment failure that would reduce system reliability), compliance with Reliability Standards TOP-001-3 and IRO-001-4 requires the Transmission Operator, Balancing Authority, and/or Reliability Coordinator to maintain reliability by taking corrective action themselves or issuing an Operating Instruction to direct the notifying

[47] As defined in the NERC Glossary, an Operating Instruction is "[a] command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System."

Generator Operator or Transmission Operator to take specific corrective action to resolve any operational issues resulting from the failure. If the Generator Operator or Transmission Operator is directed to take corrective action pursuant to an Operating Instruction, the Generator Operator or Transmission Operator must comply with those instructions according to the TOP/IRO standards.

Additionally, pursuant to TOP-002-4, Requirement R2 and R3, IRO-008-2, Requirements R2 and R3, if, as a result of an OPA, a Transmission Operator or Reliability Coordinator identifies an actual or expected SOL or IROL exceedance as a result of an issue on the system, it must develop an Operating Plan to mitigate any such exceedances and inform other functional entities of their role in the Operating Plan.[48] If the issue on the system relates to protective relay or equipment failures, the Operating Plan would address the corrective action necessary to mitigate the reliability impact of those failures and identify the appropriate entity to take such action so as to return the system to a secure and reliable state in a timely manner.

Further, pursuant to TOP-001-3, Requirement R14, each Transmission Operator must initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or RTA. Similarly, under IRO-008-2, Requirement R5, if the results of its RTA "indicate an actual or expected condition that results in, or could result in, a [SOL] or [IROL] exceedance within its Wide Area," the Reliability Coordinator must notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan.

48 *See* TOP-001-3, Requirement R14, TOP-002-4, Requirement R2 and R3, IRO-008-2, Requirements R2 and R5.

The framework established by the TOP/IRO Reliability Standards for requiring corrective action improves upon Requirement R2 of PRC-001-1.1(ii) by: (1) providing Reliability Coordinators, Balancing Authorities, and Transmission Operators the authority to determine the appropriate corrective action based on the data specifications; and (2) setting clearer expectations for the timeframes under which the corrective action must be taken.[49] Requirement R2 of PRC-001-1.1(ii) assigns the responsibility to determine the appropriate corrective action to the Generator Operator and Transmission Operator whose protective relay or equipment failed. In contrast to the construct in PRC-001-1.1(ii), the framework in the TOP/IRO Reliability Standards appropriately assigns corrective actions to those functional entities in the best position to identify the corrective actions that are necessary to return the system to a secure and reliable state.

The TOP/IRO Reliability Standards assign the responsibility to determine the appropriate corrective actions to those functional entities – Reliability Coordinators, Balancing Authorities, and Transmission Operators – with a wide-area view of the BES and greater understanding of the actions necessary to return the system to a secure and reliable state. As explained above, the TOP/IRO standards establish a framework where, under TOP-003-3 and IRO-010-2, information and data regarding protective relay and equipment failures, among other things, are sent to those functional entities with a broader view of BES conditions – e.g., from a Generator Operator to Transmission Operator and Balancing Authority, and from a Transmission Operator to a Balancing Authority, Reliability Coordinator, or other Transmission Operators. Those functional entities are then required, pursuant to TOP-001-3, TOP-002-4, IRO-001-4, IRO-002-4, and IRO-008-2 to: (i) monitor and analyze BES conditions with the appropriate inputs,[50] (ii) determine whether any

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49 In Order No. 693, the Commission directed NERC to determine the appropriate timeframe taking corrective action, as discussed further below. Order No. 693 at P 1441.

50 Specifically, as described above, Transmission Operators are required to: (1) perform OPAs pursuant to TOP-002-4, Requirement R1; (2) perform RTAs every 30 minutes pursuant to TOP-001-3, Requirement R13; and

corrective action is necessary,[51] and (iii) either take that corrective action themselves or require other functional entities to take that corrective action.[52] This framework improves reliability by placing the responsibility to determine the appropriate course of action with those entities best equipped to make those determinations through monitoring and analyzing system conditions.

Moreover, the framework established by the TOP/IRO Reliability Standards avoids the uncertainties associated with the timing element in PRC-001-1.1(ii) that Generator Operators and Transmission Operators take corrective action "as soon as possible." The objective of the "as soon as possible" language is to require entities to take corrective action on a timely basis to maintain reliable operations without specifying a uniform (or one-size-fits-all) time period to be applied in every instance. A uniform timeframe for corrective action is not appropriate because various protective relays or equipment failures present different levels of risk to reliable operation. Whereas certain failures would cause more immediate reliability issues and entities should act in a shortened timeframe (e.g., within 30 minutes or less), other failures may not cause such immediate risks to reliability and entities should have additional time to correct the issue.

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(3) perform Real-time monitoring under TOP-001-3, Requirement R10. Similarly, Reliability Coordinators are required to: (1) perform OPAs pursuant to IRO-008-2, Requirement R1; (2) perform RTAs every 30 minutes pursuant to IRO-008-2, Requirement R4; and (3) perform Real-time monitoring pursuant to IRO-002-4, Requirement R3. Balancing Authorities are also required to perform Real-time monitoring pursuant to TOP-001-3, Requirement R11.

[51] Based on the results of the OPAs, Transmission Operators are required to develop an Operating Plan for next-day operations to address actual or expected SOL exceedances and inform entities of their role under the plan, pursuant to TOP-002-4, Requirements R2 and R3. If the results of an RTA or Real-time monitoring indicate an actual or expected SOL exceedance, the Transmission Operator must initiate its Operating Plan. Similarly, Reliability Coordinators must (1) develop a coordinated Operating Plan for next-day operations to address actual or expected SOL and IROL exceedances identified as a result of its OPA and inform entities of their role under the plan, pursuant to IRO-008-2, Requirements R2 and R3, and (2) if its RTA indicates an actual or expected condition that results in, or could result in, a SOL or IROL exceedance, notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, pursuant to IRO-008-2, Requirement R5.

[52] Pursuant to Reliability Standards TOP-001-3, Requirements R1 and R2, and IRO-001-4, Requirement R1, each Transmission Operator, Balancing Authority, and Reliability Coordinator must "act to address the reliability of its [area] via direct actions or by issuing Operating Instructions."

Nevertheless, the phrase "as soon as possible" has created certain uncertainties for entities as to the timeframe under which they must take corrective action.

The Commission-approved TOP/IRO Reliability Standards, however, provide Reliability Coordinators, Balancing Authorities, and Transmission Operators the authority to set the appropriate timeframes for corrective action. If a Reliability Coordinator, Balancing Authority, or Transmission Operator issues an Operating Instruction directing other entities to take corrective action, the Operating Instruction would include a timeframe for such action. Similarly, if, as a result of an OPA, a Transmission Operator or Reliability Coordinator develops an Operating Plan to address actual or expected SOL or IROL exceedances, the Operating Plan could include the timeframe for any corrective action. The timeframes for any corrective action may thus be known to the entity required to take the action as well as the ERO in determining whether the applicable entities took corrective action on a timely basis.

This construct also improves reliability by assigning the responsibility to determine the appropriate timeframe to those functional entities with a wider view of the BES and greater understanding of the actions necessary to return the system to a secure and reliable state. As discussed above, Reliability Coordinators, Balancing Authorities, and Transmission Operators are responsible for monitoring and analyzing system conditions. As a result, these entities are in the best position to understand the appropriate timeframe for corrective action.

With the exception of IROL exceedances, the Commission-approved TOP/IRO Reliability Standards provide these entities the flexibility to develop the timeframe for corrective action based on their judgment of the facts and circumstances before them. As noted above, a uniform timeframe for all corrective action is not appropriate as different reliability issues present different levels of risks to reliable operation. Some issues require immediate attention to maintain reliability while others may be addressed on a longer time horizon. Nevertheless, Reliability Coordinators, Balancing Authorities, and Transmission Operators must set timeframes for corrective action consistent with their obligations under the Reliability Standards to maintain reliable operation. Should the Transmission Operator or Reliability Coordinator, for instance, identify an actual or expected SOL exceedance, they must develop and initiate a coordinated Operating Plan to mitigate the SOL exceedance that include timeframes for corrective action to mitigate a SOL exceedance. Although the TOP standards do not specify a timeframe by which Transmission Operators must mitigate SOL exceedances (that are not also IROL exceedances), the Transmission Operator must take action or direct others to take action on a timely basis or it could potentially violate its obligation to maintain reliability in its area (TOP-001-3, Requirement R1).

For IROL exceedances, TOP standards specifically require corrective action within 30 minutes. Reliability Standard TOP-001-3, Requirement R12 prohibits Transmission Operators from "operat[ing] outside any identified [IROL] for a continuous duration exceeding its associated IROL T_v," which is not to exceed 30 minutes. Accordingly, if a protective relay or equipment failure would cause an IROL exceedance, the Transmission Operator must take corrective action itself, or issue an Operating Instruction to another entity to take corrective action, within 30 minutes, if not sooner, or else the Transmission Operator would potentially violate TOP-001-3, Requirement R12.

2. <u>PRC-001-1.1(ii), Requirement R5</u>

The reliability objective of Requirement R5 of PRC-001-1.1(ii) to coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others is now primarily addressed by Reliability Standard TOP-003-3, as well as Reliability Standards TOP-001-3, TOP-002-4, IRO-008-2, IRO-010-2, and IRO-017-1. As discussed further below, these Reliability Standards collectively require coordination and analysis of changes in system conditions that would necessitate changes to, among other things, the Protection Systems of others.

Requirement R5 of PRC-001-1.1(ii) provides:

> **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:
>
> > **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.
> >
> > **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

Given the scope of Commission-approved Reliability Standard TOP-003-3, however, there is no longer a reliability need for a separate Requirement in PRC-001.1(ii) to address advanced notification of changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others. As further described above, TOP-003-3 provides a mechanism for Transmission Operators to obtain the data needed to fulfill their operational and planning responsibilities, including the data needed to support their OPAs, Real-time monitoring, and RTAs. Among other things, a Transmission Operator must receive data from other entities regarding changes in generation, transmission, load, or operating conditions that could affect its system, including any such changes that may necessitate modifications to its Protection Systems or RAS.

Without such data, a Transmission Operator cannot perform an OPA, consistent with TOP-002-4, to effectively projects system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. Similarly, without such data, a

Transmission Operator cannot perform an RTA, consistent with TOP-001-3, to effectively assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. A Transmission Operator must thus include in its data specifications a requirement that other entities, such as Generator Operators and other Transmission Operators, provide notice of any changes in generation, transmission, load, or operating conditions that may necessitate changes to its Protection Systems or RAS. NERC anticipates that, as part of its OPAs and RTAs, the Transmission Operator would, where necessary, verify whether any of the changes noted by Generator Operators or other Transmission Owners necessitate changes to its Protection Systems and RAS in order to maintain reliable operation. If any such changes are necessary, the Transmission Operator would include them in its Operating Plan or otherwise make the necessary changes to the Protection Systems or RAS to satisfy its obligation under TOP-001-3, Requirement R1 to take action to maintain reliability in its area.

Additionally, the data specification requirements in IRO-010-2 and the obligations in IRO-008-2 that Reliability Coordinators perform OPAs and develop coordinated Operating Plans, where necessary, further the reliability objective of Requirement R5 of PRC-001.1(ii) by including coordination with the next-day Operating Plans provided by Transmission Operators and Balancing Authorities. Like the Transmission Operator, the Reliability Coordinator has an obligation to evaluate system conditions in the day-ahead timeframe (i.e., OPAs) and in Real-time (i.e., RTAs) pursuant to IRO-008-2 and obtain data from other functional entities to perform those evaluations pursuant to IRO-010-2. Under these standards, the Reliability Coordinator must receive data on changes to generation, transmission, load or operating conditions and evaluate, via OPAs and RTAs, whether any action is necessary to maintain reliability, including making changes to Protection Systems and RAS.

The outage coordination requirements of IRO-017-1 also enhance coordination between functional entities. Reliability Standard IRO-017-1 (Outage Coordination) is a new Reliability Standard designed to ensure that outages are properly coordinated in the operations planning time horizon and Near-Term Transmission Planning Horizon. The Reliability Coordinator must establish an outage coordination process that, among other things, provides for the communication of outage schedules, assignment of coordination responsibilities, and evaluation of the impact of transmission and generation outages. The process helps identify whether any outages necessitate changes in Protection Systems or RAS. Outage information is also an input to OPAs and RTAs.

3. PRC-001-1.1(ii), Requirement R6

Pursuant to PRC-001-1.1(ii), Requirement R6, Transmission Operators and Balancing Authorities must monitor the status of each SPS in their area and notify affected Transmission Operators and Balancing Authorities of any change in status. This reliability objective is now addressed in approved Reliability Standards TOP-001-3 and TOP-003-3, making a separate requirement in PRC-001-11(ii) unnecessary. Specifically, Requirements R10 and R11 of TOP-001-3 create an affirmative obligation for Transmission Operators and Balancing Authorities to monitor the status of SPS. Specifically, TOP-001-3, Requirements R10 and R11 provide as follows:

> **R10.** Each Transmission Operator shall perform the following as necessary for determining [SOL] exceedances within its Transmission Operator Area:
>
> **10.1.** Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and
>
> **10.2.** Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.
>
> **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

The Commission-approved IRO standards also improve upon Requirement R6 of PRC-001-1.1(ii) by requiring the Reliability Coordinator to monitor the status of SPS. Specifically, IRO-002-4, Requirement R3 provides:

> **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

With respect to the notification element of Requirement R6 of PRC-001-1.1(ii), the data specification Requirements in TOP-003-3 and IRO-010-2 require entities to provide "notification of current Protection System and Special Protection System status or degradation that impacts System reliability." A separate requirement in PRC-001-1.1(ii) requiring these notifications is therefore unnecessary.

D. Resolution of Outstanding Commission Directives Related to PRC-001-1.1(ii)

In Order No. 693, the Commission approved Reliability Standard PRC-001-1 and also issued certain directives related to the meaning of the phrases "corrective action" and "as soon as possible" in Requirement R2.[53] Accordingly, the scope of Project 2007-06.2 included consideration of outstanding Commission directives from Order No. 693 related to PRC-001-1.1(ii). The following is a description of each of the Commission's outstanding directives and a discussion of the manner in which the TOP/IRO Reliability Standards approved in Order No. 817 address each of those directives.

Clarifying the Term Corrective Action: In Order No. 693, paragraphs 1439-1441, the Commission directed NERC to clarify that the term "corrective action" refers to "transmission

[53] Order No. 693 at PP 1433-49.

operators taking operator control actions" and "does not refer to troubleshooting, repairing or replacing failed relays or equipment" performed by field maintenance personnel.[54] As discussed above, NERC proposes to retire Requirement R2 of PRC-001-1.1(ii) as the new TOP/IRO standards address, in a more precise fashion, the reliability objective of requiring Transmission Operators and Generator Operators to take corrective action following protective relay or equipment failures. Pursuant to Reliability Standards TOP-001-3, Requirements R1 and R2, and IRO-001-4, Requirement R1, each Transmission Operator, Balancing Authority, and Reliability Coordinator must "act to maintain the reliability of its [area] via direct actions or by issuing Operating Instructions." The focus on action "to maintain [] reliability" and Operating Instructions, which is defined as a "command by operating personnel responsible for Real-time operation…to change or preserve the state, status, output, or input" of an Element or Facility of the BES, clarifies that the required action relates to operator control actions done on a timely basis to support reliable operations, not long-term action such as replacing failed relays and equipment.

Time for Corrective Action: In paragraphs 1444-1445 and 1449 of Order No. 693, the Commission discussed the appropriate timeframe for "corrective action" and directed NERC to develop a modification to PRC-001 to clarify the timeframe for taking corrective action. The Commission stated that the requirement for System Operators to take corrective action when protective relay or equipment failure reduces system reliability should be treated the same as the requirement for returning a system to a secure and reliable state after an IROL violation, i.e., as soon as possible, but no longer than 30 minutes after a violation as a longer time limit would place an entity in violation of relevant IROL or TOP Reliability Standards.[55] As discussed above, the

[54] Order No. 693 at PP 1439-41. Operator control actions include removing the facility without protection from service, generation re-dispatch, transmission re-configuration, etc.

[55] *Id*. at PP 1443, 1449.

timeframes for corrective action when protective relay or equipment failure reduces system reliability are now addressed in the TOP/IRO standards. Those standards, as approved by Commission, provide Reliability Coordinators, Balancing Authorities, and Transmission Operators the authority to set the appropriate timeframes for corrective action, although those timeframes must be consistent with their other requirements, including their affirmative obligation to maintain reliability in their area and not to operate outside of an IROL for longer than 30 minutes.

Timeframe for Notification of Failures: The Commission also directed NERC to modify the standard to determine a timeframe under which Generator Operators and Transmission Operators must provide the notifications of protective relay or equipment failures.[56] As discussed above, the timeframe for these notifications is now established in the data specifications required in TOP-003-3 and IRO-010-2. The periodicity and deadlines in the Transmission Operator's, Balancing Authority's, and Reliability Coordinator's data specifications must be set to allow those entities to perform their functional obligations. For instance, if certain data, such as the status of Protection Systems and RAS, is needed to perform an RTA, it must be provided every 30 minutes as Reliability Coordinators and Transmission Operators must perform RTAs every 30 minutes.[57]

PRC-001 Measures and VSLs: The Commission directed NERC to correct certain references in the Measures and VSLs to non-existent requirements.[58] As NERC proposes the retirement of PRC-001-1.1(ii), there is no need to correct these references.

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[56] *Id.* at P 1449.

[57] The TOP/IRO standards also address the comments of the California Public Utilities Commission as directed by the Commission at Order No. 693 at P 1444.

[58] *Id.* at P 1446.

E. Enforceability of the Proposed Reliability Standards

The proposed Reliability Standards include VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standards. The VRFs and VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. Exhibit F provides a detailed review of the VRFs and VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines.

The proposed Reliability Standards also include measures that support each requirement by clearly identifying what is required and how the ERO will enforce the requirement. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[59]

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the proposed Reliability Standards and definitions, and the retirement of PRC-001-1.1(ii) to become effective as set forth in the proposed Implementation Plans, provided in Exhibit B hereto. The proposed Implementation Plans for proposed Reliability Standards PER-006-1 and PRC-027-1, provided in Exhibit B hereto, provide that the proposed standards and definitions shall become effective on the first day of the first calendar quarter that is 24 months following the effective date of the Commission's order approving the standards. The 24-month implementation period will provide applicable entities sufficient time to (1) develop the training program required under proposed PER-006-1, (2) integrate the functions and limitations of Protection Systems and RAS into their OPAs and RTAs, and (3) develop and implement the process required by proposed PRC-027-1.

[59] Order No. 672 at P 327.

Applicable entities need to devote considerable resources to the development of the program and process required by the proposed standards and, in turn, require substantial lead time prior to implementation.

During the 24-month implementation period, entities must continue to comply with the Requirements in PRC-001-1.1(ii) until the proposed standards become effective, with the exception of Requirements R2, R5 and R6. Those Requirements, which, as discussed above, are being replaced by the TOP/IRO standards approved in Order No. 817, are proposed to be retired on March 31, 2017. The new TOP/IRO standards become effective on April 1, 2017.

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- the proposed Reliability Standards and associated elements included in Exhibit A, effective as proposed herein;
- the proposed Implementation Plans included in Exhibit B;
- the proposed new and revised definitions to be incorporated into the NERC Glossary included in Exhibit A; and
- the retirement of Commission-approved Reliability Standard PRC-001-1.1(ii), effective as proposed herein.

Respectfully submitted,

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Date: September 2, 2016

Exhibit A

Proposed Reliability Standards and Definitions

Exhibit A-1

Proposed Reliability Standard PRC-027-1

A. Introduction

1. **Title:** **Coordination of Protection Systems for Performance During Faults**

2. **Number:** PRC-027-1

3. **Purpose:** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Owner

   4.1.2. Generator Owner

   4.1.3. Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 below)

   4.2. Facilities: Protection Systems installed to detect and isolate Faults on BES Elements.

5. **Effective Date:** See the Implementation Plan for PRC-027-1, Project 2007-06 System Protection Coordination.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A review and update of short-circuit model data for the BES Elements under study.

1.2. A review of the developed Protection System settings.

1.3. For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.3.1. Provide the proposed Protection System settings to the owner(s) of the electrically joined Facilities.

1.3.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

1.3.3. Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

1.3.4. Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity established a process to develop settings for its Protection Systems, in accordance with Requirement R1.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six-calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the BES Element is connected, all in a time interval not to exceed six-calendar years;[1] or,
- Option 3: Use a combination of the above.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity performed Protection System Coordination Study(ies) and/or Fault current comparisons in accordance with Requirement R2.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

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[1] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. The Fault current baseline for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA). If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity may establish the baseline by performing a Protection System Coordination Study.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity utilized its settings development process established in Requirement R1, as specified in Requirement R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance with Requirements R1, R2, and R3, and Measures M1, M2, and M3 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 or Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.3. OR The responsible entity failed to establish any process in accordance with Requirement R1.
R2.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3 but was late by less than or equal to 30 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 90 calendar days. OR The responsible entity failed to perform Option 1, Option

				2, or Option 3, in accordance with Requirement R2.
R3.	N/A	N/A	N/A	The responsible entity failed to utilize the process established in accordance with Requirement R1.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee – "Power Plant and Transmission System Protection Coordination."

NERC System Protection and Control Task Force, December 7, 2006, "Assessment of Standard PRC-001-0 – System Protection Coordination."

NERC System Protection and Control Task Force, September 2006, "The Complexity of Protecting Three-Terminal Transmission Lines."

Version History

Version	Date	Action	Change Tracking
1	November 5, 2015	Adopted by NERC Board of Trustees	New standard developed under Project 2007-06

Attachment A

The following Protection System functions[2] are applicable to Requirement R2 if: (1) available Fault current levels are used to develop the settings for those Protection System functions; and (2) those Protection System functions require coordination with other Protection Systems.

21 – Distance if:

- infeed is used in determining reach (phase and ground distance), or
- zero-sequence mutual coupling is used in determining reach (ground distance).

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent

67 – AC directional overcurrent if used in a non-communication-aided protection scheme

Notes:

1. The above Protection System functions utilize current in their measurement to initiate tripping of circuit breakers. Changes in the magnitude of available Fault current can impact the coordination of these functions.
2. See the PRC-027-1 Supplemental Material section for additional information.

[2] ANSI/IEEE Standard C37.2 *Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Purpose

The Purpose states: To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.

Coordinated Protection Systems enhance reliability by isolating faulted equipment, reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. This standard requires that entities establish and implement a process to coordinate their Protection Systems to operate in the intended sequence during Faults.

Applicability

Transmission Owners, Generator Owners, and Distribution Providers are included in the Applicability of PRC-027-1 because they may own Protection Systems that are installed for the purpose of detecting Faults on the Bulk Electric System (BES). It is only those Protection Systems that are under the purview of this standard.

Transmission Owners are included in the Applicability of PRC-027-1 because they own the largest number of Protection Systems installed for the purpose of detecting Faults on the BES.

Generator Owners have Protection Systems installed for the purpose of detecting Faults on the BES. It is important that those Protection Systems are coordinated with Protection Systems owned by Transmission Owners to ensure that generation Facilities do not become disconnected from the BES unnecessarily. Functions such as impedance reaches, overcurrent pickups, and time delays need to be evaluated for coordination.

A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.

After the Protection Systems of Distribution Providers and Generator Owners are shown to be coordinated with other Protection Systems on the BES, there will be little future impact on the entities unless there are significant changes at or near the bus that interconnects with the Transmission Owner. The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current data upon request by the Distribution Provider or Generator Owner. The Distribution Provider and Generator Owner will determine whether a change in Fault current from the baseline has occurred such that a review of coordination is necessary.

Requirement R1

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults.

The reliability objective of this requirement is to have applicable entities establish a process to develop settings for coordinating their Protection Systems, such that they operate in the intended sequence during Faults. The parts that are included as elements of the process ensure the development of accurate settings, as well as providing internal and external checks to minimize the possibility of errors that could be introduced in the development of settings.

This standard references various publications that discuss protective relaying theory and application. The description of "coordination of protection" is from the pending revision of IEEE Standard C37.113-1999 (Reaffirmed: 2004), *Guide for Protective Relay Applications to Transmission Lines*, which reads:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Entities may have differing technical criteria for the development of Protection System settings based on their own philosophies. These philosophies can vary based on system topology, protection technology utilized, as well as historical knowledge; as such, a single definition or criterion for "Protection System coordination" is not practical.

The coordination of some Protection Systems may seem unnecessary, such as for a line that is protected solely by dual current differential relays. However, backup Protection Systems that are enabled to operate based on current or apparent impedance with some definite or inverse time delay must be coordinated with other Protection Systems of the BES Element such that tripping does not unnecessarily occur for Faults outside of the differential zone.

Part 1.1 A review and update of short-circuit model data for the BES Elements under study.

The short-circuit study provides the necessary Fault currents used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers. Generator Owners and Distribution Providers may not have or maintain short-circuit models; consequently, these entities would obtain the short-circuit model data from the Transmission Planners, Planning Coordinators, or Transmission Owners. Including a review and, if necessary, an update of short-circuit study information is necessary to ensure that information accurately reflects the physical power system that will form the basis of the Protection System Coordination Study and development of Protection System relay settings. The results of a short-circuit study are only as accurate as the information that its calculations are based on.

A short-circuit study is an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical Fault. Because the results of short-circuit studies are used as the basis for protective device coordination studies, the short-circuit model should accurately reflect the physical power system.

Reviews could include:

1. A review of applicable BES line, transformer, and generator impedances and Fault currents.

2. A review of the network model to confirm the network in the study accurately reflects the configuration of the actual System, or how the System will be configured when the proposed relay settings are installed.
3. A review, where applicable, of interconnected Transmission Owner, Generator Owner, and Distribution Provider information.

Part 1.2 A review of the developed Protection System settings.

A review of the Protection System settings prior to implementation reduces the possibility of introducing human error. A review is any systematic process of verifying the developed settings meet the technical criteria of the entity. Examples of reviews include peer reviews, automated checking programs, and entity-developed review procedures.

Part 1.3 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

Requirement R1, Part 1.3 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities. Communication among these entities is essential so potential Protection System coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

Part 1.3.1 1.3.1. Provide the proposed Protection System settings to the owners of the electrically joined Facilities.

Requirement R1, Part 1.3.1 requires the entity to include in its process a provision to provide proposed Protection System settings to other entities. This communication ensures that the other entities have the necessary information to review the settings and determine if there are any Protection System coordination issues.

Part 1.3.2 Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

Requirement R1, Part 1.3.2 requires the entity receiving proposed Protection System settings to include in its process a provision to respond to the entity that initiated the proposed changes. This ensures that the proposed settings are reviewed and that the initiating entity receives a response indicating Protection System coordination issues were identified, or affirmation that no issues were identified.

Part 1.3.3 Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Requirement R1, Part 1.3.3 requires the entity to include in their process a provision to verify that any identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation. This ensures that any potential impact to BES reliability is minimized.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

Note: There could be instances where coordination issues are identified and the entities agree not to mitigate all of the issues based on engineering judgment. It is also recognized that coordination issues identified during a project may not be immediately resolved if the resolution involves additional system modifications not identified in the initial project scope. Further, there could be situations where protection philosophies differ between entities, but the entities can agree that these differences do not create coordination issues.

> **Part 1.3.4** Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure.

Requirement R1, Part 1.3.4 requires the entity to communicate revisions to Protection System settings that occur due to unforeseen circumstances and differ from those developed during the planning stages of projects.

Requirement R2

This requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A:

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six-calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the BES Element is connected, all in a time interval not to exceed six-calendar years;[3] or,

[3] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. The Fault current baseline for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA). If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity may establish the baseline by performing a Protection System Coordination Study.

- Option 3: Use a combination of the above.

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. Two triggers were established for initiating a review of existing Protection System settings to allow for industry flexibility.

In the first option, an entity may choose a time-based methodology to review Protection System settings, thus eliminating the necessity of establishing a Fault current baseline and periodically performing Fault current comparisons. This option provides the entity the flexibility to choose an interval of up to six-calendar years for performing the Protection System Coordination Studies for those Protection System functions in Attachment A. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which a BES Element is connected. Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators, or Transmission Owners. This option allows the entity to choose an interval of up to six-calendar years to perform the Fault current comparisons and Protection System Coordination Studies. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. A maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) was established based on generally-accepted margins for setting Protection Systems in which incremental Fault current changes would not interfere with coordination. The 15 percent maximum deviation provides an entity with latitude to choose a Fault current threshold that best matches its protection philosophy, or other business considerations. The Fault current based option requires an entity to first establish a Fault current baseline to be used as a point of reference for future Fault current studies. The Fault current values used in the percent change calculation, whether three-phase or phase-to-ground Fault currents, are typically determined with all generation in service and all transmission BES Elements in their normal operating state.

As described in the footnote for Requirement R2, Option 2, an entity that elects to initially use Option 2 must establish its baseline prior to the effective date of the standard. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity may establish the baseline upon performing a Protection System Coordination Study. The Fault current baseline values can be updated or established when a Protection System Coordination Study is performed. The baseline values at each bus to which a BES Element is connected are updated whenever a new Protection System Coordination Study is performed for the subject

Protection System. The footnote also states that the Fault current baselines may be established for BES generating resources at the generator, the BES aggregation point for dispersed power producing resources, or at the common point of connection at 100 kV or above.

> **Example:** Prior to the effective date of PRC-027-1, an entity intending to use Option 2 of Requirement R2 establishes an initial baseline; e.g., 10,000 amps at the bus to which the BES Element under study is connected. A short-circuit review performed on March 1, 2024, for example, identifies that the Fault current has increased to 11,250 amps (12.5 percent deviation); consequently, no Protection System Coordination Study is required since the increase is below the maximum 15 percent deviation. The baseline value for the next comparison (to be performed no later than December 31, 2030) remains at 10,000 amps because no study was required as a result of the initial comparison. During the next six-year interval, Fault current comparison identifies that the Fault current has increased to 11,500 (15 percent deviation); therefore, a Protection System Coordination Study is required (and must also be completed no later than December 31, 2030), and a new baseline of 11,500 amps would be established.
>
> **Note:** In the first review described above, if the entity decides to perform a Protection System Coordination Study at the 12.5 percent deviation and the results of the study indicate that the settings still meet the setting criteria of the entity, then no settings changes are required and the baseline Fault current(s) would be updated.

As a third option, an entity has the flexibility to apply a combination of the two methodologies. For example, an entity may choose the periodic Protection System review (Option 1) and review its Facilities operated above 300 kV on a six-calendar-year interval, while choosing to use the Fault current comparison (Option 2) for its Facilities operated below 300 kV.

The Protection System functions listed in Attachment A utilize AC current in their measurement to initiate tripping of circuit breakers and the coordination of these functions is susceptible to changes in the magnitude of available short-circuit Fault current. These functions are included in Attachment A based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. Examples of functions not included in Attachment A because they do not meet both of the criteria are differential relays and Fault detectors. The numerical identifiers in Attachment A represent general device functions according to *ANSI/IEEE Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

The following provide additional information regarding the Protection System functions in Attachment A.

A “51 – AC inverse time overcurrent” relay connected to a CT on the neutral of a generator step-up transformer, referred to as “51N – AC Inverse Time Earth Overcurrent Relay (Neutral CT Method)” in ANSI/IEEE Standard C37.2, would be included in a Protection System Coordination Study. Also applicable, are “51 – AC Inverse time overcurrent” relays connected to CTs on the phases of an autotransformer for through-fault protection. Overcurrent functions used in conjunction with other functions are to be reviewed as well. An example is a definite-time overcurrent function, which is a “50 – Instantaneous overcurrent” function used in conjunction with a “62 – Time-delay” function.

If the functions listed in Attachment A are used in conjunction with other functions, they would be included in a Protection System Coordination Study provided they require coordination with other Protection Systems. An example of this is a time-delayed “21 – Distance” function, which is a “21 – Distance” function with a “62 – Time-delay” function. Another example would be a definite-time overcurrent function, which is a “50 – Instantaneous overcurrent” function with a “62 – Time-delay” function. A “50 – Instantaneous overcurrent” function used for supervising a “21 – Distance” function would not be included in a Protection System Coordination Study as it does not require coordination with other Protection Systems.

Reviewing “21 – Distance” functions is limited to those applied for phase and ground distance where infeed is used in determining the phase or ground distance setting when zero-sequence mutual coupling is used in determining the setting. Where infeed is not used in determining the setting, “21 – Distance” functions would not be included in a Protection System Coordination Study, as the reach is not susceptible to changes in the magnitude of available short-circuit Fault current. Where infeed is used in determining the reach, coordination can be affected by changes in the magnitude of available short-circuit Fault current. Two examples where infeed may be used in determining the reach, are protection for a transmission line with a long tap and a three-terminal transmission line. Ground distance functions are influenced by zero-sequence mutual coupling. The ground distance measurement can appear to be greater than or less than the true distance to a Fault when there is zero-sequence mutual coupling. The influence of zero-sequence mutual coupling changes with the magnitude of available short-circuit current. Therefore, “21 – Distance” functions would be included in a Protection System Coordination Study, when zero-sequence mutual coupling is used in determining the setting.

The 67 – AC directional overcurrent function utilized in Protection Systems for Transmission lines can be instantaneous overcurrent, inverse time overcurrent, or both instantaneous overcurrent and inverse time overcurrent. For example, in a communication-aided directional comparison blocking (DCB) scheme, the instantaneous overcurrent function is set very sensitive. When a single line-to-ground Fault occurs on a Transmission line, the Fault is detected by a number of Protection Systems for other Transmission lines. Signals from communication equipment are transmitted and received to block the other Protection Systems for the non-faulted Transmission lines from operating, thereby providing the coordination. A 67 – AC directional overcurrent function used in a permissive overreaching transfer trip scheme (POTT) relies on a signal from the remote end to operate and, therefore, does not require coordination with other Protection Systems.

Instantaneous overcurrent and/or inverse time overcurrent for a 67 – AC directional overcurrent function are utilized in a non-communication-aided Protection System for Transmission lines. As communication is not used to prevent operation for Faults outside a Protection System’s zone of protection, coordination is necessary with other Protection Systems for buses, transformers, and other Transmission lines. The instantaneous overcurrent function should be set to not overreach the end of the Transmission line. The inverse time overcurrent function should be set to coordinate with the inverse time overcurrent function of other Protection Systems. Changes in the magnitude of available Fault current can affect the coordination.

Requirement R3

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

The reliability objective of this requirement is for applicable entities to utilize the process established in Requirement R1. Utilizing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, decreases the possibility of introducing errors, and increases the likelihood of maintaining a coordinated Protection System.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes will be moved to this section.

Rationale for Requirement R1:

Coordinated Protection Systems enhance reliability by isolating faulted equipment, thus reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. The stated purpose of this standard is: "To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults." Requirement R1 captures this intent by requiring responsible entities establish a process that, when followed, allows for their Protection Systems to operate in the intended sequence during Faults. Requirement R1, Parts 1.1 through 1.3 are key elements to the process for developing Protection System settings.

Part 1.1 Reviewing and updating the short-circuit model data used to develop new or revised Protection System settings helps to assure that settings are developed using accurate, up-to-date information. Generator Owners and Distribution Providers may not have or maintain short-circuit models; consequently, these entities would obtain the short-circuit model data from the Transmission Planners, Planning Coordinators, or Transmission Owners.

Part 1.2 A review of the developed Protection System settings reduces the likelihood of introducing human error and verifies that the settings produced meet the technical criteria of the entity. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of reviews.

Part 1.3 The coordination of Protection Systems associated with BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) is essential to the reliability of the BES. Communication and review of proposed settings among these entities are necessary to identify potential coordination issues and address the issues prior to implementation of any proposed Protection System changes.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

Unforeseen circumstances could require immediate changes to Protection System settings. Requirement R1, Part 1.3.4 requires owners to include provisions to communicate those unplanned settings changes after-the-fact to the other owner(s) of the electrically joined Facilities.

Note: In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.

Rationale for Requirement R2:

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires Transmission Owners, Generator Owners, and Distribution Providers to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. The numerical identifiers in Attachment A represent general protective device functions per ANSI/IEEE *Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Requirement R2 provides entities with options to assess the state of their Protection System coordination.

Option 1 is a time-based methodology. The entity may choose to perform, at least once every six-calendar years, a Protection System Coordination Study for each of its Protection Systems identified in Attachment A. The six-calendar-year time interval was selected as a balance between the resources required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

Option 2 is a Fault current-based methodology. If Option 2 is initially selected, Fault current baseline(s) must be established prior to the effective date of this Reliability Standard. A baseline may be established when a new BES Element is installed or after a Protection System Coordination Study has been performed. The baseline(s) will be used as control point(s) for future Fault current comparisons. The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators, or Transmission Owners. In a time interval not to exceed six-calendar years following the effective date of this standard, an entity must perform a Fault current comparison. If the comparison identifies a deviation less than 15 percent, no further action is required for that six-year interval; however, if the comparison identifies a 15 percent or greater deviation in Fault current values (either three-phase or phase-to-ground) at each bus to which the BES Element is connected, the entity must also perform a Protection System Coordination Study during the same six-year interval. The baseline Fault current value(s) will be re-established whenever a new Protection System Coordination Study is performed. Fault current changes on the System not directly associated with BES modifications are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection System functions (identified in Attachment A of this standard) during Fault conditions. A Fault current deviation threshold of 15 percent or greater (as compared to the established baseline) and a maximum time interval of six calendar years were chosen for these evaluations. These parameters provide an entity with latitude to choose a Fault current threshold and time interval that best match its protection philosophy, Protection System maintenance schedule, or other business considerations, without creating risk to reliability (See the Supplemental Material section for more detailed discussion).

The footnote in Option 2 describes how an entity may change from a time-based option to a Fault current-based option for existing BES Elements as well as establishing baselines for new BES Elements by performing Protection System Coordination Studies. The footnote also states that Fault current baselines for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA).

Option 3 provides the entity the choice of using both the time-based and Fault current-based methodologies. For example, the entity may choose to utilize the time-based methodology for Protection Systems at more critical Facilities and use the Fault current-based methodology for Protection Systems at other Facilities.

Rationale for Requirement R3:

Utilizing the processes established in Requirement R1 to develop new and revised Protection System settings provides a consistent approach to the development of Protection System settings and will minimize the potential for errors.

Exhibit A-2

Proposed Reliability Standard PER-006-1

A. Introduction

1. **Title:** **Specific Training for Personnel**

2. **Number:** **PER-006-1**

3. **Purpose:** To ensure that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the Bulk Electric System.

4. **Applicability:**

    4.1. Functional Entities:

    4.1.1. Generator Operator that has:

    4.1.1.1. Plant personnel who are responsible for the Real-time control of a generator and receive Operating Instruction(s) from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center.

5. **Effective Date:** See Implementation Plan for Project 2007-06.2.

B. Requirements and Measures

R1. Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies) it operates. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M1. Each Generator Operator shall have available for inspection, evidence that the applicable personnel completed training. This evidence may be documents such as training records showing successful completion of training that includes training materials, the name of the person, and date of training.

C. Compliance

1. **Compliance Monitoring Process**

    1.1. Compliance Enforcement Authority:

    "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

    1.2. Evidence Retention:

    The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Generator Operator shall keep data or evidence of Requirement R1 for the current year and three previous calendar years.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

<table>
<tr><th rowspan="2">R #</th><th colspan="4">Violation Severity Levels</th></tr>
<tr><th>Lower VSL</th><th>Moderate VSL</th><th>High VSL</th><th>Severe VSL</th></tr>
<tr><td>R1.</td>
<td>The Generator Operator failed to provide training as described in Requirement R1 to the greater of:
one applicable personnel at a single Facility, or
5% or less of the total applicable personnel of the Generator Operator.</td>
<td>The Generator Operator failed to provide training as described in Requirement R1 to the greater of:
two applicable personnel at a single Facility, or
more than 5% and less than or equal to 10% of the total applicable personnel of the Generator Operator.</td>
<td>The Generator Operator failed to provide training as described in Requirement R1 to the greater of:
three applicable personnel at a single Facility, or
more than 10% and less than or equal to 15% of the total applicable personnel of the Generator Operator.</td>
<td>The Generator Operator failed to provide training as described in Requirement R1 to the greater of:
five or more applicable personnel at a single Facility, or
more than 15% of the total applicable personnel of the Generator Operator.
OR

The Generator Operator failed to provide training as described in Requirement R1 to its applicable personnel.</td></tr>
</table>

D. Regional Variances

None.

E. Associated Documents

Project 2007-06.2 Implementation Plan[1]

[1] http://www.nerc.com/pa/Stand/Project200706_2SystemProtectionCoordinationDL/Project_2007_06_2_Imp_Plan_Draft_1_2016_03_10_Clean.pdf

Version History

Version	Date	Action	Change Tracking
1	August 11, 2016	Adopted by the NERC Board of Trustees	New standard developed under Project 2007-06.2

Guidelines and Technical Basis

Requirement R1

The Generator Operator (GOP) monitors and controls its generating Facilities in Real-time to maintain reliability. To accomplish this, applicable plant personnel responsible for Real-time control of a generating Facility must be trained on how the operational functionality of Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility. Although, training does not have to be Facility-specific, the standard applies to plant operating personnel associated with the specific Facility to which they have Real-time control. This does not include plant personnel not responsible for Real-time control (e.g., fuel or coal handlers, electricians, machinists, or maintenance staff).

A periodicity for training is not specified in Requirement R1 because the GOP must ensure its plant personnel who have Real-time control of a generator are trained. The Generator Operator must also ensure it provides applicable training that results from changes to the operational functionality of the Protection Systems and Remedial Action Schemes that affect the output of the generation Facility(ies).

The phrase "operational functionality" focuses the training on how Protection Systems operate and prevent possible damage to Elements. It also addresses how RAS detects pre-determined BES conditions and automatically takes corrective actions.

Considerations for operational functionality may include, but are not limited to the following:

- Purpose of protective relays and RAS
- Zones of protection
- Protection communication systems (e.g., line current differential, direct transfer trip, etc.)
- Voltage and current inputs
- Station dc supply associated with protective functions
- Resulting actions – tripping/closing of breakers; tripping of a generator step-up (GSU) transformer; or generator ramping/tripping control functions

Requirement R1 focuses on the operational functionality of Protection Systems and Remedial Action Schemes specific to the generating plant and not the Bulk Electric System.

This requirement focuses on those systems that are related to the electrical output of the generator. Protective systems which trip breakers serving station auxiliary loads (e.g., such as pumps, fans, or fuel handling equipment) are not included in the scope of this training. Furthermore, protection of secondary unit substation (SUS) or low voltage switchgear transformers and relays protecting other downstream plant electrical distribution system components are not in the scope of this training, even if a trip of these devices might eventually result in a trip of the generating unit.

Rationale

Rationale for Requirement R1: Protection Systems and Remedial Action Schemes (RAS) are an integral part of reliable Bulk Electric System (BES) operation. This requirement addresses the reliability objective of ensuring that Generator Operator (GOP) plant operating personnel understand the operational functionality of Protection Systems and RAS and their effects on generating Facilities.

Exhibit A-3

Proposed Definitions

Clean Version of Proposed Definitions

Proposed Definitions

Project 2007-06 System Protection Coordination
Project 2007-06.2 Phase 2 of System Protection Coordination

Proposed Definitions

This section includes the three proposed new or modified definitions that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval, in accordance with the associated implementation plan.

New or Modified Term(s) for Glossary of Terms Used in NERC Reliability Standards

Protection System Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Operational Planning Analysis (OPA)

An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to: load forecasts; generation output levels; Interchange; known Protection System and Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Real-time Assessment (RTA)

An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load; generation output levels; known Protection System and Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Interchange; Facility Ratings; and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Redline Version of Proposed Definitions

Proposed Definitions

Project 2007-06 System Protection Coordination
Project 2007-06.2 Phase 2 of System Protection Coordination

Proposed Definitions

This section includes the three proposed new or modified definitions that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval, in accordance with the associated implementation plan.

New or Modified Term(s) for Glossary of Terms Used in NERC Reliability Standards

Protection System Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Operational Planning Analysis (OPA)

An evaluation of projected system conditions to assess anticipated (pre~~-~~-Contingency) and potential (post~~-~~-Contingency) conditions for next~~-~~-day operations. The evaluation shall reflect applicable inputs including, but not limited to~~,~~: load forecasts; generation output levels; Interchange; known Protection System and ~~Special Protection System~~Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third~~-~~-party services.)

Real-time Assessment (RTA)

An evaluation of system conditions using Real~~-~~-time data to assess existing (pre~~-~~-Contingency) and potential (post~~-~~-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load~~,~~; generation output levels~~,~~; known Protection System and ~~Special Protection System~~Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages~~,~~; generator outages~~,~~; Interchange~~,~~; Facility Ratings~~,~~; and identified phase angle and equipment limitations. (Real~~-~~-time Assessment may be provided through internal systems or through third~~-~~-party services.)

Exhibit B

Implementation Plans

Exhibit B-1

Implementation Plan for Project 2007-06 System Protection Coordination

Implementation Plan

Project 2007-06 System Protection Coordination

Approvals Requested

- PRC-027-1 – Coordination of Protection Systems for Performance During Faults

Retirements Requested

- PRC-001-1.1(ii) – System Protection Coordination[1]

Prerequisite Approvals (for Retirements Requested)

- PER-006-1 – Specific Training for Personnel
- Definition of "Operational Planning Analysis"
- Definition of "Real-time Assessment"

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 of PRC-027-1)

New or Modified Term(s) for Glossary of Terms Used in NERC Reliability Standards

Protection System Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Effective Date of New or Revised Standards

PRC-027-1 – Coordination of Protection Systems for Performance During Faults

Reliability Standard PRC-027-1 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental

[1] The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of both proposed Reliability Standards PRC-027-1 and PER-006-1, and the proposed definitions for "Operational Planning Analysis" and "Real-time Assessment." NERC is proposing the complete retirement of PRC-001-1.1(ii) in the implementation plans associated with both PRC-027-1 and PER-006-1. The Project 2007-06 System Protection Coordination Mapping Document shows how PRC-027-1 addresses requirements R3 and R4 of PRC-001-1.1(ii). The remaining requirements of PRC-001-1.1(ii) – Requirements R1, R2, R5, and R6 are proposed for retirement in Project 2007-6.2 Phase 2 of System Protection Coordination (see the Mapping Document for Project 2007-06.2 Phase 2 of System Protection Coordination).

authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Effective Date for New or Modified NERC Glossary Terms

The NERC Glossary Term "Protection System Coordination Study" shall become effective on the effective date for PRC-027-1.

Retirements

PRC-001-1.1(ii) – System Protection Coordination

PRC-001-1.1(ii) – System Protection Coordination shall be retired at midnight of the day immediately prior to the day that PER-006-1 and PRC-027-1 become effective.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Exhibit B-2

Implementation Plan for Project 2007-06.2 – Phase 2 of System Protection Coordination

Implementation Plan

Project 2007-06.2 Phase 2 of System Protection Coordination

Requested Approvals

- PER-006-1 – Specific Training for Personnel
- Definition of "Operational Planning Analysis"
- Definition of "Real-time Assessment"

Requested Retirements

- PRC-001-1.1(ii) – System Protection Coordination[1]

Prerequisite Approvals

- PRC-027-1 – Coordination of Protection Systems for Performance During Faults

Applicable Entities

- Generator Operator (applicable to PER-006-1 only)
- Reliability Coordinator (applicable to definitions only)
- Transmission Operator (applicable to definitions only)

General Considerations

There are a number of factors that influence the determination of the implementation period for the proposed standard and revised definitions. The following factors address the Balancing Authority, Generator Operator, and Transmission Operator:

1. The effort and resources by the Generator Operator to provide training to plant personnel to address the operational functionality of Protection Systems and Remedial Action Schemes at individual generating Facilities in PER-006-1 that the Generator Operator may not have been addressing under PRC-001-1.1(ii), Requirement R1.

2. Maintain consistency with the Implementation Plan of the approved Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards[2] that are applicable to the Balancing Authority and Transmission Operator. This

[1] The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of both proposed Reliability Standards PRC-027-1 and PER-006-1, and the proposed definitions for "Operational Planning Analysis" and "Real-time Assessment." NERC is proposing the complete retirement of PRC-001-1.1(ii) in the implementation plans associated with both PRC-027-1 and PER-006-1. The Project 2007-06 System Protection Coordination Mapping Document shows how PRC-027-1 addresses requirements R3 and R4 of PRC-001-1.1(ii). The remaining requirements of PRC-001-1.1(ii) – Requirements R1, R2, R5, and R6 are proposed for retirement in Project 2007-6.2 Phase 2 of System Protection Coordination (see the Mapping Document for Project 2007-06.2 Phase 2 of System Protection Coordination).
[2] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order No. 817, 153 FERC ¶ 61,178 (2015).

project explains how the retirement of PRC-001-1.1(ii) Requirements R1, R2, R5, and R6 are addressed by the TOP/IRO sets standards.

3. Maintaining consistency with the Implementation Plan of the approved TOP/IRO standards[3] that are applicable to the Balancing Authority and Transmission Operator in the application of the revised definitions of "Operational Planning Analysis" and "Real-time Assessment" (effective January 1, 2017) in the *NERC Glossary of Term Used in NERC Reliability Standards*. See the Project 2007-06.2 Mapping Document for additional details.

4. The amount of time needed by the Transmission Operator in PRC-001-1.1(ii), Requirement R1 and Reliability Coordinator (not applicable to PRC-001-1.1(ii)) to train on Protection Systems and Remedial Action Schemes in order to be capable of integrating their functions and limits into their Operational Planning Analysis and Real-time Assessment.

Effective Dates

PER-006-1 – Specific Training for Personnel

Where approval by an applicable governmental authority is required, Reliability Standard PER-006-1 – Specific Training for Personnel shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Operational Planning Analysis and Real-time Assessment

Where approval by an applicable governmental authority is required, the definitions "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA) in the NERC Glossary of Terms Used in NERC Reliability Standards shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving the definition, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirements

PRC-001-1.1(ii) – System Protection Coordination

Requirement R1

PRC-001-1.1(ii) – System Protection Coordination, Requirement R1 shall be retired immediately prior to the effective date of PER-006-1 (*Specific Training for Personnel*) and the revised definitions of

[3] Id.

"Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA), or as otherwise provided for by an applicable governmental authority.

Requirement R2, R5, and R6

PRC-001-1.1(ii) – System Protection Coordination, Requirement R2, R5, and R6 shall be retired at midnight of March 31, 2017, or as otherwise provided for by an applicable governmental authority.

Requirements R3 and R4

See Project 2007-06 System Protection Coordination Implementation Plan.[4]

Retirement of Existing Standards and Definitions

The currently-approved definitions of "Operations Planning Analysis" and "Real-time Assessment" shall be retired immediately prior to the effective date of the revised definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA), or as otherwise provided for by an applicable governmental authority.

[4] http://www.nerc.com/pa/Stand/Project%20200706%20System%20Protection%20Coordination%20DL/Implementation_Plan_PRC-027-1_clean_10012015.pdf

Exhibit C

Order No. 672 Criteria

EXHIBIT C

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standards meet or exceed the criteria.

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

The proposed Reliability Standards achieve the specific reliability goals of: (1) maintaining the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System ("BES") Elements, such that those Protection Systems operate in the intended sequence during Faults; and (2) requiring registered entities to provide training to their relevant personnel on Protection Systems and Remedial Action Schemes ("RAS") to help ensure that the BES is reliably operated. The proposed Reliability Standards articulate clear objectives for each of the areas.

2. **Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]**

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The proposed Reliability

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at PP 321, 324.

[3] Order No. 672 at PP 322, 325.

Standards clearly articulate the actions that applicable entities must take to comply with the standards.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment, as discussed further in Exhibit F. The assignment of the severity level for each VSL is consistent with the corresponding requirement. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner. [5]

The proposed Reliability Standards contain measures that support each requirement by clearly identifying what is required to demonstrate compliance. These measures help provide clarity regarding the manner in which the requirements will be enforced, and help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

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4 Order No. 672 at P 326.

5 Order No. 672 at P 327.

5. **Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]**

The proposed Reliability Standards achieve the reliability goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standards clearly articulate the objectives that applicable entities must meet and provide entities the flexibility to tailor their processes and plans required under the standard to best suit the needs of their organization.

6. **Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]**

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standards contains significant benefits for the Bulk-Power System. The requirements of the proposed Reliability Standards help ensure that entities coordinate their Protection Systems with neighbors and are familiar with the operational functionality of the relevant Protection Systems and RAS.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]**

The proposed Reliability Standards apply throughout North America and do not favor one geographic area or regional model.

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[6] Order No. 672 at P 328.

[7] Order No. 672 at P 329-30.

[8] Order No. 672 at P 331.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

The proposed Reliability Standards have no undue negative impact on competition. The proposed Reliability Standards require the same performance by each applicable entity. The standards do not unreasonably restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective dates for the proposed Reliability Standards are just and reasonable and appropriately balance the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop and implement the necessary procedures and policies. The proposed implementation periods will allow applicable entities adequate time to meaningfully implement the requirements. The proposed effective dates are explained in the proposed Implementation Plan, attached as Exhibit B.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standards were developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards. Exhibit G includes a summary of the development proceedings, and details the processes followed to develop the proposed Reliability Standards. These processes included, among other things, comment and balloting periods. Additionally, all meetings of the drafting

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9 Order No. 672 at P 332.

10 Order No. 672 at P 333.

11 Order No. 672 at P 334.

team were properly noticed and open to the public. The initial and additional ballots achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standards. No comments were received that indicated the proposed Reliability Standards conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

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[12] Order No. 672 at P 335.

[13] Order No. 672 at P 323.

Exhibit D

Mapping Documents

Exhibit D-1

Mapping Document for Project 2007-06 System Protection Coordination

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Mapping of Requirements from PRC-001-1.1(ii) to PRC-027-1

Project 2007-06 System Protection Coordination

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.	Being proposed to be moved to a new TOP Reliability Standard by Project 2007-06.2 Phase 2: System Protection Coordination	N/A
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	Being proposed for retirement by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. • Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition. R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	PRC-027-1: Requirements R1 and R2 Note: Applicability changed to GO, TO and DP	R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: 1.1 A review and update of short-circuit models for the BES Elements under study. 1.2 A review of the developed Protection System settings. 1.3 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to: 1.3.1 Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities. 1.3.2 Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified. 1.3.3 Verify that identified coordination issue(s) associated with the proposed Protection System settings for the

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		associated BES Elements are addressed prior to implementation. 1.3.4 Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during: 1.3.4.1. Implementation or commissioning. 1.3.4.2. Misoperation investigations. 1.3.4.3. Maintenance activities. 1.3.4.4. Emergency replacements made due to failures of Protection System components. R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A: • Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or • Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years; or • Option 3: A combination of the above. R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.
R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	PRC-027-1: Requirements R1 and R2 Note: Applicability changed to GO, TO and DP	R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: 1.1 A review and update of short-circuit models for the BES Elements under study. 1.2 A review of the developed Protection System settings. 1.3 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to: 1.3.1 Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		1.3.2 Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified. 1.3.3 Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation. 1.3.4 Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during: 1.3.4.1. Implementation or commissioning. 1.3.4.2. Misoperation investigations. 1.3.4.3. Maintenance activities. 1.3.4.4. Emergency replacements made due to failures of Protection System components. R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		with Protection System functions identified in Attachment A: • Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or • Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years; or • Option 3: A combination of the above. R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.
R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others: R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could	Being proposed for retirement by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
require changes in the Transmission Operator's Protection Systems. R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.		
R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Being proposed for retirement by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Exhibit D-2

Mapping Document for Project 2007-06.2 – Phase 2 of System Protection Coordination

Mapping Document

Project 2007-06.2 Phase 2 of System Protection Coordination

Revisions or Retirements to Already Approved Standards

This mapping document explains how each of the existing Requirements (R1, R2, R5, and R6) of PRC-001-1.1(ii) (*System Protection Coordination*)[1] are being revised or retired. If a requirement is being proposed for revision, the revised, new, and/or supporting requirement(s) will be identified in the center column. If a requirement is being proposed for retirement, the center column will describe the proposed action and any requirement(s) used to support the action. Revisions and retirements will be accompanied by an explanation or justification listed in the right column. Capitalized terms, unless otherwise noted, are those found in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary").[2] References to regulatory directives are specifically related to Order No. 693 ("Order").[3] Standards or definitions listed as "existing" are enforceable and those listed as "approved" have been adopted by the NERC Board of Trustees and approved by the Federal Energy Regulatory Commission ("FERC"). Check the NERC website for effective dates. The functional entities discussed in the mapping document are the Balancing Authority (BA), Generator Operator (GOP), Planning Coordinator (PC), Reliability Coordinator (RC), Transmission Operator (TOP), and Transmission Planner (TP). The term "TOP/IRO" refers to the Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) sets of Reliability Standards that were filed under NERC Project 2014-03 – Revisions to TOP and IRO Standards[4] and approved by FERC.[5] The explanation herein assumes that the term, "Special Protection

[1] Federal Energy Regulatory Commission (FERC) approved PRC-001-1.1(ii), effective May 29, 2015.
[2] *Glossary of Terms Used in NERC Reliability Standards*. December 7, 2015. (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).
[3] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[4] http://www.nerc.com/pa/Stand/Pages/Project-2014-03-Revisions-to-TOP-and-IRO-Standards.aspx
[5] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order 817, 153 FERC ¶ 61,178 (November 19, 2015).

System"[6] (SPS) will be replaced by the term "Remedial Action Scheme"[7] (RAS). In the referenced Reliability Standards herein the term SPS may be replaced by RAS; therefore, the term RAS will be used in the "Comments" column throughout.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing)[8,9] **R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall be	PRC-001-1.1(ii), Requirement R1 is proposed for retirement.	**Introduction** The reliability objective of PRC-001-1.1(ii), Requirement R1 is to ensure that the BA,

[6] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Special Protection System is defined as "[a]n automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme."

[7] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), the proposed definition of Remedial Action Scheme is defined as "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as: Meet requirements identified in the NERC Reliability Standards; Maintain Bulk Electric System (BES) stability; Maintain acceptable BES voltages; Maintain acceptable BES power flows; Limit the impact of Cascading or extreme events." See definition for additional information on the definition of RAS.

[8] Order No. 693 at P 1418. "Protection and Control systems (PRC) on Bulk-Power System elements are an integral part of reliable grid operation. Protection systems are designed to detect and isolate faulty elements on a system, thereby limiting the severity and spread of system disturbances, and preventing possible damage to protected elements. The function, settings and limitations of a protection system are critical in establishing SOLs and IROLs. The PRC Reliability Standards apply to transmission operators, transmission owners, generator operators, generator owners, distribution providers and regional reliability organizations and cover a wide range of topics related to the protection and control of power systems."

[9] Order No. 693 at P 1435. "Protection systems on Bulk-Power System elements are an integral part of reliable operations. They are designed to detect and isolate faulty elements on a power system, thereby limiting the severity and spread of disturbances and preventing possible damage to protected elements. If a protection system can no longer perform as designed because of a failure of its relays, system reliability is reduced or threatened. In deriving SOLs and IROLs, moreover, the functions, settings, and limitations of protection systems are recognized and integrated. Systems are only reliable when protection systems perform as designed. This is what PRC-001-1 means in linking a reduction in system reliability with a protection relay failure or other equipment failure."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
familiar with the purpose and limitations of Protection System schemes applied in its area. **Operational Planning Analysis (Approved)** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages;	Being "familiar with the purpose and limitations of Protection System schemes" will be clarified as (1) being "familiar with their purpose," and (2) being "familiar with their limitations" as follows: • The phrase "Protection systems schemes" maps to the NERC Glossary terms of Protection Systems and Remedial Action Schemes. • Being "familiar with the purpose" is addresses by existing and proposed training standards. • Being "familiar with the limitations" together with the clarification found in Order No. 693 at P 1418 and P 1435 along with the revised	GOP, and TOP are "familiar with the purpose and limitations of Protection System[12] schemes applied in its area." The reliability objective of the phrase "Protection System schemes" in PRC-001-1.1(ii), Requirement R1 is also intended to include RAS. The functions and limitations of a Protection Systems and RAS are critical in establishing System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL) such that the Bulk Electric System[13] (BES) is operated within these limits. The following explains how being familiar with the purpose and limitations of Protection Systems and RAS will be addressed according to issue beginning with

[12] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Protection System is defined as:
"Protection System -
- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."

[13] See Glossary of Terms Used in NERC Reliability Standards (updated December 7, 2015).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Real-time Assessment (Approved)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)	definitions of NERC Glossary defined terms of Operational Planning Analysis and Real-time Assessment address the reliability objective of PRC-001-1.1(ii), Requirement R1 as explained in the Comments column to the right. **PER-006-1 (New)** **4.** Applicability: **4.1.** Functional Entities: **4.1.1.** Generator Operator that have: **4.1.1.1.** Plant personnel who are responsible for the Real-time control of a generator and receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center. This does not include personnel at a centrally located dispatch center.	"familiarity with their limitations" and then "familiarity with their purpose." **Familiar with their limitations** When the BA, GOP, and TOP are familiar with the limitations of Protection Systems and RAS, the entities are able to operate the BES in such a manner that Protection Systems and RAS will be operated within their limits and be able to detect and isolate faulty Elements, thereby, limiting the severity and spread of system disturbances, and preventing possible damage to protected Elements. When the GOP is familiar with the operational functionality of Protection Systems and RAS by being trained on how Protection Systems operate and prevent possible damage to Elements, the GOP is capable of operating to its full capability within its area, meaning the output of its generation Facilities. When the BA is familiar with the limitations of Protection Systems and RAS, it is capable

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	R1. Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies) it operates. **PER-003-1 (Existing)** **R1.** Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate: **1.1.** Areas of Competency **1.1.1.** Resource and demand balancing **1.1.2.** Transmission operations **1.1.3.** Emergency preparedness and operations	of maintaining generation, Load, and Interchange balance. The BA ensures that RAS in its area are enabled when needed for system reliability. When the TOP is familiar with limitations of Protection Systems and RAS, it will be capable of identifying when system reliability is reduced or threatened. In operating to established SOLs and IROLs, it is important that the functions and limitations of Protection Systems and RAS are recognized and integrated by the TOP into operating the BES reliably. The BES is only reliable when Protection Systems and RAS perform within their limitations. **Familiarity with the Purpose** Familiarity with the purpose of Protection Systems and RAS is achieved through training, as explained below, according to each applicable entity (BA, GOP, and TOP) in PRC-001-1.1(ii) and the RC that is not applicable to this standard, but has been

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	1.1.4. System operations **1.1.5.** Protection and control **1.1.6.** Voltage and reactive **1.1.7.** Interchange scheduling and coordination **1.1.8.** Interconnection reliability operations and coordination **R2.** Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates: **2.1.** Areas of Competency **2.1.1.** Transmission operations **2.1.2.** Emergency preparedness and operations **2.1.3.** System operations **2.1.4.** Protection and control	included to address a potential gap in reliability. **Familiarity with the Purpose (GOP)** For the GOP, the Reliability Standard PER-006-1 (*Specific Training for Personnel*) proposes to replace PRC-001-1.1(ii), Requirement R1. The PER-006-1 standard identifies applicable GOP personnel that are responsible for the Real-time control of a generator and that receive Operating Instructions from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center. This applicability removes ambiguity over which personnel of the GOP are intended to be familiar with the purpose Protection Systems and RAS. Centrally located personnel are not included here because they are addressed by PER-005-2 (*Operations Personnel Training*). Personnel at centrally located dispatch centers will receive company-specific Protection System and RAS training, if identified, as a reliability-

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	2.1.5. Voltage and reactive **2.2.** Certificates • Reliability Operator • Balancing, Interchange and Transmission Operator • Transmission Operator **R3.** Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificate: **3.1.** Areas of Competency **3.1.1.** Resources and demand balancing **3.1.2.** Emergency preparedness and operations **3.1.3.** System operations **3.1.4.** Interchange scheduling and coordination	related task via the PER-005-2, Requirement R6. Here the GOP must use "…a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1. of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations." Being trained using a systematic approach on the purpose (i.e., functions, including limitations) Protection Systems and RAS will enable the GOP centrally located dispatch personnel to ensure reliable operation of its Facilities on the BES. The phrase "…purpose and limitations…" in PRC-001-1-1(ii), Requirement R1 is addressed in the proposed Requirement R1 through the use of "operational functionality." The phrase "operational functionality" as described in the PER-006-1 – Supplemental Material describes that training is expected to cover how Protection Systems operate within their limitations and prevent possible damage to Elements. It also

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	3.2. Certificates • Reliability Operator • Balancing, Interchange and Transmission Operator • Balancing and Interchange Operator **PER-005-2 (Approved)** **R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: **1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-	addresses how RAS detect pre-determined BES conditions and automatically take corrective actions. The criteria that comprises operational functionality mirror the components listed under the NERC Glossary term "Protection System." By doing so, reduces the ambiguity of the phrase "purpose and limitations." The phrase "…applied in its area" is addressed by the PER-006-1 by using "…that affect the output of the generating Facility it operates." Lastly, the proposed PER-006-1 Requirement R1 includes both Protection Systems and RAS to eliminate confusion over the phrase "Protection System schemes." **Familiarity with the Purpose (BA)** For the BA, the PRC-001-1.1(ii), Requirement R1 is proposed for retirement on the basis that the BA obtains an appropriate level of familiarity with the purpose of Protection

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	related tasks identified in part 1.1 each calendar year. **1.2.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1. **1.3.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program. **1.4.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall	Systems and RAS under PER-003-1 (*Operating Personnel Credentials*), Requirement R3 and PER-005-2, Requirements R1, R3, R4, and R5 as explained below in detail. The BA is certified under PRC-003-1 as a System Operator.[14] Although there is no specific area of competency for protection and control similar to the Reliability Coordinator and Transmission Operator certifications, the NERC *Balancing and Interchange Operator Certification Exam Content Outline 2015*[15] (BI Exam) does contain the same five topics applicable to RC and less one topic applicable to the TOP. The topic that is not included is to "analyze relay targets, fault locaters and fault recorders to determine a proper restoration plan" and is not germane to BA operations. The job-task

[14] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a System Operator is defined as: An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System (BES) in Real-time.
[15] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Balancing%20and%20Interchange%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	implement the changes identified. **R2.** (Omitted – Transmission Owner, not applicable) **R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1. or Requirement R2 part 2.1. **3.1.** Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in	analyses (JTA) performed by entities are used to (1) develop the BI Exam topics that are evaluated by NERC and a NERC functional entity working group every three years, and (2) used to develop the training of personnel on company-specific reliability-related tasks under PER-005-2. Protection and control topics are addressed in the BI Exam outline under two areas: System Operations and Emergency Preparedness and Operations, and include the following five topics: • Analyze the impact of protection equipment outages on system reliability. • Ensure special protective systems and remedial action schemes are enabled when needed for system reliability. • Maintain adequate protective relaying during all phases of the system restoration.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Requirement R1 part 1.1. or Requirement R2 part 2.1. **R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. **4.1.** A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously	• Take action in response to alarms from special protective schemes. • Schedule system telecommunications, telemetering, protection, and control equipment outages to ensure system reliability. There is another certification that includes an integrated certification of both the BA and TOP called the *Balancing, Interchange, and Transmission Operator Certification Exam Content Outline 2015*[16] (BIT Exam). This BIT Exam outline does include protection and control as an area of competency and contains the same topics found in the *Transmission Operator Certification Exam Content Outline 2015*. Under PER-005-2, the System Operator and Operation Support Personnel of the BA are identified in the requirements. To address the reliability objective of "shall be familiar

[16] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Balancing%20Interchange%20Transmission%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria. **R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. **5.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training. **R6.** Each Generator Operator shall use a systematic approach to develop and	with the purpose and limitations of Protection System schemes applied in its area," the BA uses its JTA to develop a list of its reliability-related tasks. Using its documented methodology, the BA must develop and implement training materials according to its training program (R1) using a systematic approach to training. The BA is required to verify the capabilities of its System Operators under Requirement R3. Under Requirement R4, the BA "that (1) has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1[17] with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that

[17] Requirement R2 is omitted here because it is applicable to the Transmission Owner and is not within the scope of this project.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	implement training to its personnel identified in Applicability Section 4.1.5.1. of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. **6.1.** Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training. **Operational Planning Analysis (OPA) (Revised)** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to: load forecasts; generation output levels; Interchange; known Protection System and **Remedial Action Scheme** status or	replicates the operational behavior of the BES." Requirement R5 addresses the Operations Support Personnel of the BA, which requires the BA to use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 that are applicable to System Operators. **Familiarity with the Purpose (TOP)** The TOP will ensure that the BES is operated within SOLs and IROLs by integrating the "functions and limitations" of Protection Systems and RAS into its OPA and RTA as proposed by the revisions to the definitions of OPA and RTA. For the TOP, the PRC-001-1.1(ii), Requirement R1 is proposed for retirement

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	degradation, **functions, and limitations**; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)[10] **Real-time Assessment (RTA) (Revised)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load; generation output levels; known Protection System and **Remedial Action Scheme** status or degradation, **functions, and limitations**; Transmission outages; generator outages;	on the basis that the TOP obtains a sufficient level of knowledge (i.e. be familiar with the purpose of Protection System schemes applied in its area) under PER-003-1 (*Operating Personnel Credentials*), Requirement R1 and PER-005-2, Requirements R1, R3, R4, and R5, as explained below in detail. The TOP is certified as a System Operator, and has an "area of competency" for "protection and control" as shown in the NERC *Transmission Operator Certification Exam Content Outline 2015*.[18] This represents a minimum competency in the area of protection and control. However, certified System Operators will receive company-specific training on Protection Systems and RAS through PER-005-2, Requirements. The job-task analyses (JTA) performed by entities are used to (1)

[10] Bolded text identifies the proposed revisions.
[18] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Transmission%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Interchange; Facility Ratings; and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)[11] **IRO-008-2 (Approved)** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its	develop the TO Exam topics that are evaluated by NERC and a NERC functional entity working group every three years, and (2) used to develop the training of personnel on company-specific reliability-related tasks under PER-005-2. Under PER-005-2, System Operator and Operation Support Personnel of the TOP are identified in the requirements. To address the reliability objective of “shall be familiar with the purpose and limitations of Protection System schemes applied in its area,” the TOP uses its JTA to develop a list of its reliability-related tasks. Using its documented methodology, the TOP must develop and implement training materials according to its training program (R1) using a systematic approach to training. The TOP is required to verify the capabilities of its System Operators under Requirement R3. Under Requirement R4, the TOP “that (1)

[11] Bolded text identifies the proposed revisions.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1[19] with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES." Requirement R5 addresses the Operations Support Personnel of the TOP, which requires the TOP to use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1. Operations Support Personnel are among the personnel that perform Operational

[19] Requirement R2 is omitted here because it is applicable to the Transmission Owner and is not within the scope of this project.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	IRO-010-2 (Approved) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.1.** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data.	Planning Analyses (OPA) and Real-time Assessments (RTA). These reliability-related-tasks, include performing both an OPA and RTA and are proposed for modification to address the integration of Protection System and RAS functions and limitations to ensure the BES is operated within SOLs and IROLs. See the discussion below concerning the OPA and RTA for the explanation of how the revised definitions support the reliability objective of PRC-001-1.1(ii), Requirement R1. **Reliability Coordinator (RC)** The standard PRC-001-1.1(ii) did not include the RC as an applicable functional entity; however, the RC is included here to further support the explanation on how the RC, along with the TOP, ensures the BES is operated within SOLs and IROLs by integrating the functions and limitations of

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	1.4. The deadline by which the respondent is to provide the indicated data. **TOP-001-3 (Approved)** **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **TOP-002-4 (Approved)** **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its	Protection Systems and RAS into its OPA and RTA. The RC obtains a sufficient level of knowledge (i.e. be familiar with the purpose and limitations of Protection System schemes applied in its area) under PER-003-1 (*Operating Personnel Credentials*), Requirement R1 and PER-005-2, Requirements R1, R3, R4, and R5. The RC is certified as a System Operator, and has an "area of competency" for "protection and control" as shown in the NERC *Reliability Coordinator Certification Exam Content Outline 2015*.[20] This represents a minimum competency in the area of protection and control. However, certified System Operators will receive company-specific training on Protection Systems and RAS through PER-005-2, Requirements.

[20] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Reliability%20Coordinator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement / Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **R3.** Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).	Under PER-005-2, System Operator and Operation Support Personnel of the RC are identified in the requirements. To similarly address the reliability objective of "shall be familiar with the purpose and limitations of Protection System schemes applied in its area" in PRC-001-1.1(ii), Requirement R1, the RC uses its JTA to develop a list of its reliability-related tasks. Using its documented methodology, the RC must develop and implement training materials according to its training program (R1) using a systematic approach to training. The RC is required to verify the capabilities of its System Operators under Requirement R3. Under Requirement R4, the RC that (1) has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1[21] with emergency

[21] Requirement R2 is omitted because it is applicable to the Transmission Owner and is not within the scope of this project.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES." Requirement R5 addresses the Operations Support Personnel of the RC, which requires the RC to use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1. Operations Support Personnel are among the personnel that perform Operational Planning Analyses (OPA) and Real-time Assessments (RTA). These reliability-related tasks include performing both an OPA and RTA and are proposed for modification to address the integration of Protection System and RAS functions and limitations to ensure the BES is operated within SOLs and IROLs. See the discussion below concerning the OPA and

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		RTA for the explanation of how the revised definitions support the reliability objective of PRC-001-1.1(ii), Requirement R1. **Operational Planning Analysis (OPA)** The TOP, applicable to PRC-001-1.1(ii), Requirement R1, is required have an OPA that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its SOLs (TOP-002-4, Requirement R1). The TOP is required to have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified as a result of its OPA as required in Requirement R1 (TOP-002-4, Requirement R2) and notify others of their role in the Operating Plan(s) (TOP-002-4, Requirement R4). To accomplish this, the TOP is required to maintain a documented data specification for the data necessary to perform its OPA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		System reliability (TOP-003-3, Requirement R1, Part 1.2.). The RC is not applicable to PRC-001-1.1(ii) and is included here for additional support. The RC is required to perform an OPA that will allow it to assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area (IRO-008-2, Requirement R1). The RC is required to have a coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances identified as a result of its OPA as performed in Requirement R1 (IRO-008-2) while considering the Operating Plans for the next-day provided by its TOPs and BAs (IRO-008-2, Requirement R2). To accomplish this the RC is required to maintain a documented data specification for the data necessary to perform its OPA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		System reliability (IRO-010-2, Requirement R1, Part 1.2.). **Real-time Assessment (RTA)** The TOP, applicable to PRC-001-1.1(ii), Requirement R1, is required to ensure that an RTA is performed at least once every 30 minutes (TOP-001-3, Requirement R13). The TOP is required to initiate its Operating Plan to mitigate a SOL exceedance identified as part of its RTA (TOP-001-3, Requirement R14). To accomplish this the TOP is required to maintain a documented data specification for the data necessary to perform its RTA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts System reliability (TOP-003-3, Requirement R1, Part 1.2.). The RC is not applicable to PRC-001-1.1(ii) and is included here for additional support. The RC is required to ensure that a RTA is performed at least once every 30 minutes (IRO-008-4, Requirement R4). The RC is

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		required to notify impacted Transmission Operators and Balancing Authorities within its RC Area, and other impacted RCs as indicated in its Operating Plan, when the results of a RTA indicate an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area (IRO-008-2, Requirement R5). To accomplish this the RC is required to maintain a documented data specification for the data necessary to perform its RTA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts System reliability (IRO-010-2, Requirement R1, Part 1.2.).
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	PRC-001-1.1(ii), Requirements R2, R2.1., and R2.2. are proposed for retirement. The subsequent sections are organized in the following manner: • Corrective Action,	**Introduction** **Requirement PRC-001-1.1(ii), Requirement R2** The reliability objective of Requirement R2 and its sub-requirements ensure that the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	• Time Frame for corrective actions • Time Frame for notifications, • Shall notify, and • Protection System Inputs for notification	GOP and TOP take corrective action, as soon as possible, if a protective relay or equipment failure reduces system reliability. The subsequent explanation provides detail on how the TOP/IRO set of Reliability Standards (e.g., IRO-001-4, IRO-008-2, IRO-010-2, TOP-001-3, and TOP-003-3) that were developed since the Order was issued achieve the reliability objectives of PRC-001-1.1(ii), Requirement R2 and its sub-requirements. **Directives** Included in the explanation below is how these Reliability Standards address the directives in the Order at P 1441, 1444, 1445 and 1449 (#2 and #3). **Other** The phase "relay or equipment" in PRC-001-1.1(ii), Requirement R2 is clarified by the use of the defined NERC Glossary term, "Protection System" and "RAS."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing	PRC-001-1.1(ii), Requirements R2, R2.1., and R2.2. are proposed for retirement. Corrective action in Requirements R2, R2.1. and R2.2. is covered by: **TOP-001-3 (Approved)** **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission	**Introduction – Corrective Action** The directive at P 1449 (#3) of the Order states that: "…transmission operators must carry out corrective control actions, i.e., return a system to a stable state that respects system requirements…" This directive is addressed in the TOP/IRO standards that were developed since the Order was issued because the BA, RC, and TOP can issue Operating Instructions[22] to maintain the reliability of its respective area. The following describes how the TOP/IRO Reliability Standards achieve the reliability objective with regard to "corrective actions." **Corrective Action by the GOP – R2.1.** TOP-003-3 (*Operations Reliability Data*)

[22] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Operating Instruction is defined as "[a] command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)"

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Authorities. The Transmission Operator shall take corrective action as soon as possible. **PRC-001-1.1(ii) (Existing)**	Operator Area via its own actions or by issuing Operating Instructions. **R2.** Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. **TOP-003-3 (Approved)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	Requirement R1 and part 1.2. that was developed since the Order was issued addresses corrective action by the GOP because the TOP will be aware of current Protection System and SPS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the TOP receives such notification. TOP-001-3 (*Transmission Operations*) Furthermore, the TOP will act to maintain the reliability of its Transmission Operator Area[23] (TOP Area) by issuing Operating Instructions to the GOP under TOP-001-3, Requirement R1. TOP-003-3 (*Operations Reliability Data*)

[23] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Transmission Operator Area is defined as "[t]he collection of Transmission assets over which the Transmission Operator is responsible for operating."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	Similarly, TOP-003-3, Requirement R2 and part 2.2. that was developed since the Order was issued, addresses corrective action by the GOP because the BA (i.e., Host BA[24]) will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the BA receives such notification. The BA will act to maintain the reliability of its Balancing Authority Area[25] (BA Area) by issuing Operating Instructions to the GOP under TOP-001-3, Requirement R2. **Corrective Action by the TOP – R2.2.** TOP-003-3 (*Operations Reliability Data*)

[24] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Host Balancing Authority is defined as:

1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries.
2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.

[25] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Balancing Authority Area is defined as "[t]he collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.		Requirement R1 and part 1.2. that was developed since the Order was issued addresses corrective action by the TOP because the TOP will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the TOP receives such notification. TOP-001-3 (*Transmission Operations*) The TOP will act to maintain the reliability of its TOP Area by issuing Operating Instructions under TOP-001-3, Requirement R2. TOP-003-3 (*Operations Reliability Data*) Similarly, TOP-003-3, Requirement R2 and part 2.2. that was developed since the Order was issued addresses corrective action by the BA because the BA will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**IRO-010-2 (Approved)** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **IRO-001-4 (Approved)** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.”	reliability. See the “shall notify” section(s) below for a full description of how the TOP receives such notification. The BA will act to maintain the reliability of its BA Area by issuing Operating Instructions under TOP-001-3, Requirement R2. IRO-010-2 (*Reliability Coordinator Data Specification and Collection*) Requirement R1 and part 1.2. that was developed since the Order was issued addresses corrective action by the RC because the RC will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the “shall notify” section(s) below for a full description of how the RC receives such notification. IRO-001-4 (*Reliability Coordination - Responsibilities and Authorities*) Under Requirement R1, the RC will act to address the reliability of its Reliability

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		Coordinator Area[26] (RC Area) by issuing Operating Instructions.
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing	PRC-001-1.1(ii), Requirements R2, R2.1, and R2.2. are proposed for retirement. The time frame for corrective action in Requirements R2, R2.1. and R2.2. is covered by:	**Introduction – Time frame for corrective actions** The directive at P 1441 directs the ERO to clarify the term "corrective action" consistent with the discussion in the Order when it modifies PRC-001-1 in the Reliability Standards development process. The reasoning for addressing a time frame for corrective actions is amplified in P 1443 of the Order, which states that: "As explained above *[in the previous paragraphs of the Order*], the requirement for system operators to take corrective control action when protective relay or equipment failure reduces system reliability should be treated the same as the requirement for returning a system to a secure and reliable state after an

[26] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Balancing Authority Area is defined as "[t]he collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Authorities. The Transmission Operator shall take corrective action as soon as possible. **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its		Interconnection Reliability Operating Limit (IROL) violation, i.e., as soon as possible, but no longer than 30 minutes after a violation. A longer time limit would place an entity in violation of relevant IROL or TOP Reliability Standards."[27] At P 1444 of the Order, FERC directed NERC to consider the comments of the California PUC regarding the term "as soon as possible" as applicable to the maximum time frame for corrective action through the Standards development process. At P 1445 of the Order, FERC directed NERC, through the Reliability Standards development process, to determine the appropriate amount of time after the detection of relay failures, in which relevant transmission operators must be informed of such failures.

[27] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Interconnection Reliability Operating Limit is defined as "[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**TOP-001-3 (Approved)** **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.	The Order at P 1449 (#3) directs NERC to clarify that, after being informed of failures in relays or protection system elements that threaten reliability of the Bulk-Power System, transmission operators must carry out corrective control actions, i.e., return a system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes after they receive notice of the failure. **PRC-001-1.1(ii), R2.1. & R2.2. (time frame for corrective actions)** For the reasons explained below, a less than one-hour time frame criteria for corrective action will achieve the reliability objective directed in the Order at P 1441, 1444, 1445, and 1449 (#2 and #3). TOP-001-3 (*Transmission Operations*)

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the	**R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.	Requirement R13 requires the TOP to ensure that a Real-time Assessment[28] ("RTA") is performed at least once every 30 minutes and initiate its Operating Plan[29] to mitigate a System Operating Limit[30] (SOL) exceedance identified as part of its Real-time[31] monitoring or RTA in TOP-001-3, Requirement R14. The RTA requires inputs to include current Protection System and RAS status (change in status is implied) or

[28] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Real-time Assessment is defined as "[a]n evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)"

[29] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Operating Plan is defined as "[a] document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan."

[30] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a System Operating Limit is defined as "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)"

[31] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), Real-time is defined as "[p]resent time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)"

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**IRO-008-2 (Approved)** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.	degradation (including failure) from a BA, GOP, and/or TOP. Under TOP-003-3 notification of these inputs must occur within a 30 minute time frame; otherwise, a valid RTA cannot be performed once every 30 minutes. Given the periodicity for obtaining the data and performing the RTA, the exposure (i.e., time frame) for taking corrective action "as soon as possible" is expected to be less than one hour. The TOP may issue Operating Instructions to maintain reliability upon the notification of Protection System or RAS status (change in status is implied) or degradation (including failure) because the exposure is not expected to exceed one hour. The TOP must act under TOP-001-3, Requirement R1 to maintain the reliability of its TOP Area via its own actions or by issuing Operating Instructions. IRO-008-2 (*Reliability Coordinator Operational Analyses and Real-time Assessments*), Requirement R4 requires the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	TOP-003-3 (Approved) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection	RC to ensure that an RTA is performed at least once every 30 minutes. The RTA requires inputs to include current Protection System and RAS status (change in status is implied) or degradation (including failure) from a BA, GOP, and/or TOP. TOP-003-3 (*Operations Reliability Data*) IRO-010-2 (*Reliability Coordinator Data Specification and Collection*) Under TOP-003-3 (TOP and BA) and IRO-010-2 (RC) notification of these inputs must occur within a 30 minute time frame; otherwise, a valid RTA cannot be performed once every 30 minutes. Given the periodicity for obtaining the data and performing the RTA, the exposure (i.e., time frame) for taking corrective action as soon as possible is expected to be less than one hour. The RC may issue Operating Instructions to maintain reliability upon the notification of Protection System or RAS status (change in status is implied) or degradation (including failure) because the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	System status or degradation that impacts System reliability. **IRO-010-2 (Approved)** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **IRO-001-4 (Approved)** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.	exposure is not expected to exceed one hour. IRO-001-4 (*Reliability Coordination - Responsibilities and Authorities*) The RC must act under IRO-001-4, Requirement R1 to maintain the reliability of its RC Area via its own actions or by issuing Operating Instructions.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	PRC-001-1.1(ii), Requirements R2, R2.1., and R2.2 are proposed for retirement. The time frame for notification in Requirements R2, R2.1. and R2.2. is covered by: **IRO-008-2 (Approved)** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **TOP-001-3 (Approved)**	**Introduction – Time frame for notifications and shall notify** The directive at P 1444 of the Order directed NERC to consider the comments of FirstEnergy about the time frame between actual failure and its discovery (i.e., notification) in relation to the maximum time frame for corrective action through the Standards development process. The Order at P 1445 and 1449 (#2) directed NERC to determine an appropriate amount of time after the detection of relay failures and the time in which relevant generation and transmission operators must be informed of such failure. **PRC-001-1.1(ii), R2.1. & R2.2. (time frame for notifications)** TOP-001-3 (*Transmission Operations*) For the reasons explained below concerning notification, it is inferred that the timeframe for notification must occur on at least a 30

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	**R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **TOP-003-3 (Approved)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis	minute interval because the RTA performed by the RC (IRO-008-2) and TOP (TOP-001-3) once every 30 minutes requires the data to be available on at least a 30 minute basis such that the exposure is less than one hour. TOP-003-3 (*Operations Reliability Data*) Notification in PRC-001-1.1(ii), Requirement R2.1. and R2.2. is addressed by TOP-003-3, Requirement R1, part 1.2. for TOP and Requirement R2, part 2.2. for BA that were developed since the Order was issued. Requirements R1 and R2 mandate that the TOP and BA have provisions (i.e., inputs) for notification of Protection System and RAS status (change in status is implied) or degradation (including failures) that impacts System reliability. **PRC-001-1.1(ii), R2.1. (shall notify)** Based on the conclusions above (i.e., “time frame for corrective actions”), notifications of the inputs of Protection Systems and RAS

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible. **PRC-001-1.1(ii) (Existing)**	functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. **R4.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	by the GOP must be provided on at least a 30-minute basis. The TOP/IRO set of standards that were developed since the Order was issued achieve the reliability objective of ensuring that the BA (i.e., Host BA) and TOP are notified of protective relay and equipment failures. TOP-003-3 (*Operations Reliability Data*) TOP-003-3, Requirement R1 mandates the TOP have a documented specification for the data necessary for the TOP to perform an Operational Planning Analysis ("OPA"),[32] Real-time monitoring, and RTA. Both the OPA and RTA, by definition, require an evaluation that reflects inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure). TOP-003-3, Requirement R3 mandates the TOP distribute its documented

[32] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Operational Planning Analysis is defined as "[a]n evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: **5.1.** A mutually agreeable format **5.2.** A mutually agreeable process for resolving data conflicts **5.3.** A mutually agreeable security protocol. **TOP-003-3 (Approved) (included again for reference)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The	specification to those entities that have the required data, which includes the GOP. TOP-003-3, Requirement R2 mandates the BA have a documented specification for the data necessary for the BA to perform its analysis functions and Real-time monitoring that include inputs from Protection System and RAS status (change in status is implied) or degradation that are necessary to maintain generation-Load-Interchange balance. TOP-003-3, Requirement R4 mandates the BA to distribute its documented specification to those entities that have the required data, which includes the GOP. TOP-003-3, Requirement R5 builds upon the previous Requirements R1, R2, R3, and R4 described above. Requirement R5 mandates that any GOP that receives a data specification (pursuant to Requirement R3 or R4) satisfy the obligations of the documented specifications using: a mutually agreeable format, a mutually agreeable

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.	process for resolving data conflicts, and a mutually agreeable security protocol. Therefore, the reliability objective of PRC-001-1.1(ii) Requirement R2, R2.1 that mandates the GOP notify its TOP and Host BA of protective relay and equipment failures is addressed by the documented specification for the data required in TOP-003-3, Requirement R1, part 1.2. for TOP and Requirement R2, part 2.2. for the BA. The documented data specifications is required to be distributed by the TOP and BA and mandates the GOP, per TOP-003-3 Requirement R5, provide current Protection System and RAS status (change in status is implied) or degradation that impacts System reliability. **PRC-001-1.1(ii), R2.2. (shall notify)** Based on the conclusions above (i.e., "time frame for corrective actions), notifications of the inputs of Protection Systems and RAS by the TOP must be provided on at least a 30-minute basis. The TOP/IRO set of standards

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	TOP-003-3 (Approved) (included again for reference) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection	that were developed since the Order was issued achieve the reliability objective of ensuring that the RC and the BA and TOP (i.e., the affected BA and TOP) are notified of protective relay and equipment failures. TOP-003-3 (*Operations Reliability Data*) TOP-003-3, Requirement R1, mandates the TOP have a documented specification for the data necessary for the TOP to perform an OPA, Real-time monitoring, and RTA. Both the OPA and RTA, by definition, require an evaluation to reflect inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure). TOP-003-3, Requirement R3 mandates the TOP distribute its documented specification to those entities that have the required data, which includes the BA, RC, and TOP. TOP-003-3, Requirement R2 mandates the BA have a documented specification for the data necessary for the BA to perform its analysis functions and Real-time monitoring,

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.	which would include inputs from Protection System and RAS status (change in status is implied) or degradation that are necessary to maintain generation-Load-Interchange balance. TOP-003-3, Requirement R4 mandates the BA distribute its documented specification to those entities that have the required data, which includes the BA, RC, and TOP. TOP-003-3, Requirement R5 builds upon the previous Requirements R1, R2, R3, and R4 described above. Requirement R5 mandates that any TOP that receives a data specification (pursuant to Requirement R3 or R4) satisfy the obligations of the documented specifications using: a mutually agreeable format, a mutually agreeable process for resolving data conflicts, and a mutually agreeable security protocol. **Common to both the GOP and TOP** IRO-010-2 (*Reliability Coordinator Data Specification and Collection*)

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	IRO-010-2 (Approved) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	Requirement R1, mandates the RC have a documented specification for the data necessary for the RC to perform an OPA, Real-time monitoring, and RTA. Both the OPA and RTA, by definition, require an evaluation to reflect inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure). IRO-010-2, Requirement R2 mandates the RC distribute its documented specification to those entities that have the required data, which includes the BA, RC, and TOP. IRO-010-2, Requirement R3 builds upon the previous Requirements R1 and R2 described above. Requirement R3 mandates that a TOP that receives a data specification (pursuant to Requirement R2) satisfy the obligations of the documented specifications using: a mutually agreeable format, a mutually agreeable process for resolving data conflicts, and a mutually agreeable security protocol.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		Therefore, the reliability objective of PRC-001-1.1(ii) Requirement R2, R2.2. mandates the TOP to notify its RC and affected BA and TOP of protective relay and equipment failures is addressed by the documented specification for the data required in TOP-003-3, Requirement R1, part 1.2. for the TOP and Requirement R2, part 2.2. for the BA, and IRO-010-2, Requirement R1 for the RC. The documented data specifications is required to be distributed by the TOP and will require the RC per IRO-010-2, Requirement R3 and the BA and TOP per TOP-003-3, Requirement R5 to provide current Protection System and RAS status (change in status is implied) or degradation that impacts System reliability.
PRC-001-1.1(ii) (Existing) **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.	**PRC-027-1 (NERC Board approved)** The mapping of PRC-001-1.1(ii), Requirements R3, R3.1 and R3.2 are addressed in a different project. See Project 2007-06 System Protection Coordination	N/A

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. • Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition. **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	(i.e., Phase 1) concerning proposed Reliability Standard PRC-027-1.	
PRC-001-1.1(ii) (Existing) **R4.** Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators,	**PRC-027-1 (NERC Board approved)** The mapping of PRC-001-1.1(ii), Requirement R4 is addressed in a different project. See Project 2007-06 System Protection Coordination (i.e., Phase 1)	N/A

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Transmission Operators, and Balancing Authorities.	concerning proposed Reliability Standard PRC-027-1.	
PRC-001-1.1(ii) (Existing) **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems. **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	PRC-001-1.1(ii), Requirements R5, R5.1, and R5.2 are proposed for retirement. The notification in advance in Requirements R5, R5.1 and R5.2 is covered by:	**Introduction – Shall notify in advance** For the reasons explained under the "shall notify" sections above, the TOP will receive notifications of known current Protection Systems and RAS status (change in status is implied) or degradation (including failure) from the GOP and TOP under TOP-003-3 that was developed since the Order was issued. Advance notification to the TOP will occur through IRO-008-2, IRO-017-1 (*Outage Coordination*), and TOP-002-4 (*Operations Planning*) that were developed since the Order was issued, and through the existing TPL-001-4 (*Transmission System Planning Performance Requirements*). **PRC-001-1.1(ii), R5.1 and R5.2 (shall notify in advance)**

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating	**TPL-001-4 (Existing)** **R4.** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case	The following explains how the reliability objective of the GOP and TOP coordinating changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of other TOPs is met. TPL-001-4 (*Transmission System Planning Performance Requirements*) Requirement R4 (Requirement R2 is inferred by reference) focuses on the Planning Assessment[33] performed by either the PC or the TP with aspects of Protection Systems and RAS. Additionally, the projected Contingency conditions that are evaluated under TPL-001-4 by the PC and TP are considered by the TOP in performing an OPA.

[33] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Planning Assessment is defined as a "[d]ocumented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
conditions that could require changes in the Protection Systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems. **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	analyzed in accordance with Requirements R2, Parts 2.1.4. and 2.4.3. The Corrective Action Plan(s) shall: **IRO-002-4 (Approved)** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **TOP-002-4 (Approved)** **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning	IRO-002-4 (*Reliability Coordination — Monitoring and Analysis*) Requirement R3 supports the inclusion of the Reliability Coordinator. This function also has a responsibility to have knowledge (i.e. be familiar with the purpose and limitations) of Protection Systems and RAS since it is monitoring Facilities, the status of RAS, and non-BES facilities. TOP-002-4 (*Operations Planning*) The approved TOP-002-4, Requirement R1 that was developed since the Order was issued requires the TOP to have an OPA that will allow the TOP to assess whether its planned operations for the next day (i.e., "in advance") within its TOP Area will exceed any of its SOLs. The OPA requires inputs to

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.	Analyses, Real-time monitoring, and Real-time Assessments. **TOP-003-3 (Approved)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	assess anticipated (pre-Contingency[34]) and potential (post-Contingency) conditions for next-day operations. The TOP when performing its next-day planning through an OPA, will receive the necessary data "in advance" under TOP-003-3 and evaluate the projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for when generation, transmission, load, or operating conditions that could require changes in the other Transmission Operator's Protection Systems. By definition, an OPA evaluation shall reflect applicable inputs including Protection System and RAS status (change in status is implied) or degradation, but is not limited to: • load forecasts,

[34] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Contingency is defined as "[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	**IRO-008-2 (Approved)** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System	• generation output levels, • Interchange, • known Protection System and RAS status or degradation, • Transmission outages, • generator outages, • Facility Ratings, and • identified phase angle and equipment limitations. IRO-008-2 (*Reliability Coordinator Operational Analyses and Real-time Assessments*) IRO-008-2, Requirement R2 requires each RC to have coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances. These exceedances are identified as a result of an OPA being performed in IRO-008-2, Requirement R1 while considering the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **IRO-017-1 (Approved)** **R3.** Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. **R4.** Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or	Operating Plans for the next-day provided by each BA and TOP. Collectively, performing the OPA under TOP-002-4 using the necessary inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure), the Planning Assessment conducted under TPL-001-4, the jointly developed solutions under IRO-017-2, communication from the RC to the TOP under IRO-005-4, and the coordinated Operating Plan(s) under IRO-008-2 achieve the reliability objective of both PRC-001-1.1(ii), Requirements R5.1 and R5.2 for "when changes in generation, transmission, load, or operating conditions could require changes in the other Transmission Operator's Protection Systems." IRO-017-1 (*Outage Coordination*) IRO-017-1, Requirement R3 requires each PC and TP to provide its Planning Assessment to an impacted RC. IRO-017-1, Requirement R4 requires each PC and TP to jointly develop

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.	solutions with each respective RC for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.[35]
PRC-001-1.1(ii) (Existing) **R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Requirement R6 is being proposed for retirement. The monitoring and notification in Requirement R6 is covered by: **IRO-002-4 (Approved)** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability	**PRC-001-1.1(ii), R6 (monitoring and notification of RAS)** IRO-002-4 (*Reliability Coordination — Monitoring and Analysis*) The reliability objective for the monitoring of RAS is addressed by IRO-002-4, Requirement R3 for the Reliability Coordinator.

[35] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Near-Term Transmission Planning Horizon is defined as "[t]he transmission planning period that covers Year One through five."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Operating Limit exceedances within its Reliability Coordinator Area. **TOP-001-3 (Approved)** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **10.1.** Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and **10.2.** Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency	TOP-001-3 (*Transmission Operations*) The reliability objective for the monitoring of RAS is addressed by TOP-001-3, Requirements R10 and R11 for the TOP and BA, respectively, because they are required to monitor the status of a RAS. Notification of the change in status is addressed for the reasons explained under the “shall notify” sections above. In summary, the BA and TOP will receive notifications of inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure) from the applicable GOP and/or TOP under TOP-003-3 that was developed since the Order was issued.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	TOP-003-3 (approved) included by reference. See the section called, “shall notify.”	

Exhibit E

Evaluation of Proposed Definitions for Project 2007-06.2 – Phase 2 of System Protection Coordination

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Evaluation of Proposed Definitions

Project 2007-06.2 – Phase 2 of System Protection Coordination

Introduction

The following definitions are proposed for revision under the Project 2007-06.2 – Phase 2 of System Protection Coordination. The definitions of "Operating Planning Analysis" (OPA) and "Real-time Assessment" (RTA) are used in the Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards.[1] To address the reliability objective of PRC-001-1.1(ii) – *Protection System Coordination*, Requirement R1 to "be familiar with the purpose and limitations of Protection System schemes in its area," the two definitions are being modified to include the phrase "…functions, and limitations…" to ensure the Transmission Operator (TOP), consider the functions and limitations of Protection Systems and Remedial Action Schemes (RAS) in their OPA and RTA evaluations. The PRC-001-1(ii) standard is not applicable to the Reliability Coordinator (RC), however, the modifications to the definitions affect this entity. Revising the definitions to require the RC and the TOP to integrate the functions and limitations (i.e., purpose and limitations) into its OPA and RTA will ensure that the Bulk Electric System (BES) is operated within System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL).

Proposed Definitions

This section includes the Reliability Standards and the associated requirements where the two modified terms are found. These two terms are not found within the proposed PER-006-1 standard, but are an integral part of the basis for the retirement of PRC-001-1.1(ii), Requirement R1. There are two significant revisions, (1) an administrative update to replace "Special Protection System" to "Remedial Action Scheme" (RAS), and (2) the addition of the phrase "…functions, and limitations…" to address the reliability objective of PRC-001-1.1(ii), Requirement R1 for the applicable TOP that must integrate the "functions and limitations" into these evaluations. The proposed definition revisions also have an effect on the Reliability Coordinator that is not applicable to PRC-001-1.1(ii). The bold text in the "Proposed Definitions" column accentuate the revisions.

[1] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order No. 817, 153 FERC ¶ 61,178 (2015).

Definitions (Effective January 1, 2017)	Proposed Definitions
Operational Planning Analysis An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)	**Operational Planning Analysis (OPA)** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to**:** load forecasts; generation output levels; Interchange; known Protection System and **Remedial Action Scheme** status or degradation**, functions, and limitations**; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Real-time Assessment An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)	**Real-time Assessment (RTA)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load**;** generation output levels**;** known Protection System and **Remedial Action Scheme** status or degradation**, functions, and limitations;** Transmission outages**;** generator outages**;** Interchange**;** Facility Ratings**;** and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Evaluation

The following is an evaluation of the potential impacts the modifications to the above definitions may have on the expected performance by the RC and TOP. The evaluation is limited to the Reliability Standards that will be or become in effect upon approval of the revised definitions.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-002-4 – Reliability Coordination – Monitoring and Analysis (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments.	The OPA definition revision has an impact on the RC in this requirement. The RC must include in its data exchange capability the "functions and limitations" of Protection Systems and RAS needed to perform an OPA.
IRO-008-2 - Reliability Coordinator Operational Analyses and Real-time Assessments (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall perform an *Operational Planning Analysis* that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its *Operational Planning Analysis* as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.	**Requirement R1** The OPA definition revision has an impact on the RC in this requirement. The RC must integrate the "functions and limitations" of Protection Systems and RAS in order to assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area. **Requirement R2** The OPA definition revision has no impact on the RC in this requirement. This requirement references that the results of the OPA are used by the RC to have a coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-010-2 – Reliability Coordinator Data Specification and Collection (Effective April 1, 2017) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.1.** A list of data and information needed by the Reliability Coordinator to support its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments.	**Requirement R1** The OPA definition revision has an impact on the RC in this requirement. The data needed by the RC regarding the "functions and limitations" of Protection Systems and RAS to support performing an OPA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of OPA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2). **Requirement R2** The OPA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the OPA to others.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-014-3 - Coordination Among Reliability Coordinators (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1.** Criteria and processes for notifications. **1.2.** Energy and capacity shortages. **1.3.** Control of voltage, including the coordination of reactive resources. **1.4.** Exchange of information including planned and unplanned outage information to support its *Operational Planning Analyses* and Real-time Assessments. **1.5.** Provisions for periodic communications to support reliable operations.	The OPA definition revision has no impact on the RC in this requirement. Part 1.4 references that the RC must include information about planned and unplanned outages that support its OPA.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-002-4 – Operations Planning (Effective April 1, 2017) **R1.** Each Transmission Operator shall have an *Operational Planning Analysis* that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its *Operational Planning Analysis* as required in Requirement R1.	**Requirement R1** The OPA definition revision has an impact on the TOP in this requirement. The TOP must integrate the "functions and limitations" of Protection Systems and RAS in order to assess whether its planned operations for the next day within its TOP Area will exceed any of its SOLs. **Requirement R2** The OPA definition revision has no impact on the TOP in this requirement. The TOP is using information resulting from its OPA.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-003-3 – Operational Reliability Data (Effective April 1, 2017) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.1.** A list of data and information needed by the Transmission Operator to support its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessment.	**Requirement R1** The OPA definition revision has an impact on the TOP in this requirement. The data needed by the TOP regarding the "functions and limitations" of Protection Systems and RAS to support performing an OPA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of OPA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2.). **Requirement R2** The OPA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the OPA to others.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-002-4 – Reliability Coordination – Monitoring and Analysis (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*.	The RTA definition revision has an impact on the RC in this requirement. The RC must include in its data exchange capability the "functions and limitations" of Protection Systems and RAS needed to perform an RTA.
IRO-008-2 – Reliability Coordinator Operational Analyses and Real-time (Effective April 1, 2017) **R4.** Each Reliability Coordinator shall ensure that a *Real-time Assessment* is performed at least once every 30 minutes. **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a *Real-time Assessment* indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	**Requirement R4** The RTA definition revision has an impact on the RC in this requirement. The RC must include the "functions and limitations" among other prescribed inputs from the definition of RTA. **Requirement R5** The RTA definition revision has no impact on the RC in this requirement. The RC is notifying others based on the results of its RTA that an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-009-2 - Reliability Coordinator Actions to Operate Within IROLs (Effective January 1, 2016) **R2.** Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or *Real-time Assessment*. **R3.** Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the Reliability Coordinator's Real-time monitoring or *Real-time Assessment*.	**Requirement R2** The RTA definition revision has no impact on the RC in this requirement. The RC will be taking an action to prevent an IROL exceedance, as identified in the RC's RTA. **Requirement R3** The RTA definition revision has no impact on the RC in this requirement. The RC will be acting or directing others so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the RC's RTA.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-010-2 – Reliability Coordinator Data Specification and Collection (Effective April 1, 2017) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*. The data specification shall include but not be limited to: **1.1.** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments* including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*.	**Requirement R1** The RTA definition revision has an impact on the RC in this requirement. The data needed by the RC regarding the "functions and limitations" of Protection Systems and RAS to support performing an RTA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of RTA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2.). **Requirement R2** The RTA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the RTA to others.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-014-3 - Coordination Among Reliability Coordinators (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1.** Criteria and processes for notifications. **1.2.** Energy and capacity shortages. **1.3.** Control of voltage, including the coordination of reactive resources. **1.4.** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and *Real-time Assessments*. **1.5.** Provisions for periodic communications to support reliable operations.	The RTA definition revision has no impact on the RC in this requirement. Part 1.4 references that the RC must include information about planned and unplanned outages that support its RTA.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-001-3 – Transmission Operations (Effective April 1, 2017) **R13.** Each Transmission Operator shall ensure that a *Real-time Assessment* is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or *Real-time Assessment*.	**Requirement R13** The RTA definition revision has an impact on the TOP in this requirement. The TOP must include the "functions and limitations" among the other prescribed inputs from the definition of RTA. **Requirement R14** The RTA definition revision has no impact on the TOP in this requirement. The TOP will be initiating its Operating Plan to mitigate a SOL exceedance identified in its RTA.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-003-3 – Operational Reliability Data (Effective April 1, 2017) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*. The data specification shall include, but not be limited to: **1.1.** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments* including non-BES data and external network data as deemed necessary by the Transmission Operator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and *Real-time Assessment*.	**Requirement R1** The RTA definition revision has an impact on the TOP in this requirement. The data needed by the TOP regarding the "functions and limitations" of Protection Systems and RAS to support performing an RTA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of RTA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2.). **Requirement R2** The RTA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the RTA to others.

Exhibit F

Analysis of Violation Risk Factors and Violation Severity Levels

Exhibit F-1

Analysis of Violation Risk Factors and Violation Severity Levels for Reliability Standards PRC-027-1

Violation Risk Factor and Violation Severity Level Justification Document

Project 2007-06 System Protection Coordination

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in Federal Energy Regulatory Commission (FERC) approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System (BPS). In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange

- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance
Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A VRF of Medium is appropriate for this requirement because failure by an entity to establish a process to develop settings for its Bulk Electric System (BES) Protection Systems to operate in the intended sequence during Faults could directly affect the electrical state or the capability of the BES. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems. However, a violation of this requirement is unlikely to lead to BES instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) system modeling and data exchange. Requirement R1 mandates that entities establish a process to address all aspects of BES Protection System coordination, including the updating of modeling information and the exchange of Protection System data with other owners, when applicable.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The requirement utilizes Parts to specify items that must be addressed within the settings development process. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-2, Requirements R1 and R2, which are related to developing and documenting a Protection System Maintenance Program and have VRFs of Medium.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A VRF of Medium is appropriate for this requirement because failure by an entity to establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could directly affect the electrical state or the capability of the BPS. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems. However, a violation of this requirement is unlikely to lead to BES instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 or Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.3. OR The responsible entity failed to establish any process in accordance with Requirement R1.

VSL Justifications for PRC-027-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no "consequence of lowering the current level of compliance."
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the High and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSLs use language similar to that used in the associated requirement and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSLs are based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-027-1, Requirement R2	
VRF for Requirement R2 is Medium	
NERC VRF Discussion	A VRF of Medium is appropriate for this requirement because failure to periodically perform a Protection System Coordination Study for existing Protection Systems could lead to failure in identifying and addressing changes in Fault current that have accumulated over time. These deviations in Fault current could result in miscoordinated Protection Systems which could, under anticipated Emergency, abnormal, or restorative conditions, directly and adversely affect the electrical state or the capability of the BES or the ability to effectively monitor and control the BES. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems. However, a violation of this requirement is unlikely to lead to BES instability, separation, or cascading failures.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BES. Requirement R2 relates to one of these areas; specifically, protection systems and their coordination. Requirement R2 mandates that entities periodically perform Protection System Coordination Studies or Fault current comparisons to verify Protection Systems remain coordinated.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-1, Requirement R3, which relates to periodically performing comprehensive assessments to evaluate the effectiveness of UVLS Programs.

VRF Justifications for PRC-027-1, Requirement R2	
VRF for Requirement R2 is Medium	
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A VRF of Medium is appropriate for this requirement because failure to periodically perform a Protection System Coordination Study for existing Protection Systems could lead to failure in identifying and addressing changes in Fault current that have accumulated over time. These deviations in Fault current could result in miscoordinated Protection Systems which could, under anticipated Emergency, abnormal, or restorative conditions, directly and adversely affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems. However, a violation of this requirement is unlikely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3 but was late by less than or equal to 30 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 90 calendar days. OR The responsible entity failed to perform Option 1, Option 2, or Option 3, in accordance with Requirement R2.

VSL Justifications for PRC-027-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no "consequence of lowering the current level of compliance."

the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the proposed VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSLs use language similar to that used in the associated requirement and is, therefore, consistent with the requirement.
FERC VSL G4	The VSLs are based upon a single violation, not a cumulative number of violations.

Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justifications for PRC-027-1, Requirement R3	
VRF for Requirement R3 is High	
NERC VRF Discussion	A VRF of High is appropriate for this requirement because failure by an entity to utilize its process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could place the BES at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS. Requirement R2 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) system modeling and data exchange. Requirement R3 mandates that entities utilize their process established in Requirement R1 that incorporates all actions necessary to to develop settings for its BES Protection Systems to operate in the intended sequence during Faults.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.

VRF Justifications for PRC-027-1, Requirement R3	
VRF for Requirement R3 is High	
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-2, Requirements R3 and R4, which are related to implementing time-based and performance-based maintenance program(s) respectively for Protection Systems.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A VRF of High is appropriate for this requirement because failure by an entity to utilize its process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could place the BES at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to utilize the process established in accordance with Requirement R1.

VSL Justifications for PRC-027-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no "consequence of lowering the current level of compliance."
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses language similar to that used in the associated requirement and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

Exhibit F-2

Analysis of Violation Risk Factors and Violation Severity Levels for Reliability Standards PER-006-1

Violation Risk Factors and Violation Severity Level Justifications

Project 2007-06.2 Phase 2 of Protection System Coordination
PER-006-1 – Specific Training for Personnel

This document provides the Protection System Coordination Phase 2 Standard Drafting Team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for the proposed PER-006-1 – Specific Training for Personnel.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability

to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System: [2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

[1] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] *Id*. at footnote 15.

Guideline (3) — Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels,[3] FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance[4]

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties[5]

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement[6]

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations[7]

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

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[3] *Order on Violation Severity Levels Proposed by the Electric Reliability Organization*, 123 FERC ¶61,284 (2008).

[4] *Id*. at P20

[5] *Id*. at P22

[6] *Id*. at P32

[7] *Id*. at P35

VRF Justifications – PER-006-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	In this requirement, each Generator Operator (GOP) is required to train its plant personnel on the operational functionality of Protection Systems and Remedial Action Schemes that affect output of a generating Facility. It is unlikely that this requirement in the planning time frame, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, a violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. The PRC-001-1.1(ii), Requirement R1 that will be replaced by PER-006-1, Requirement R1 has a VRF of High. The VRF of High is associated with the performance of the Balancing Authority (BA) and Transmission Operator (TOP) as they have a greater responsibility for ensuring reliable operation of the bulk electric system. The requirement for these entities to be familiar with the purpose and limitations of Protection System schemes in its area is addressed by the Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards and various requirements identified in the project mapping document. These requirements are appropriately assigned VRFs of Medium and High, therefore, does not require the GOP to also have a VRF of High. The Medium VRF is consistent with the training Requirements in the PER-005-2 (*System Personnel Training*) Reliability Standard, which includes the GOP, BA, TOP, and Reliability Coordinator.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This Requirement is consistent with the intent of Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.

VRF Justifications – PER-006-1, Requirement R1	
Proposed VRF	**Medium**
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The Requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The Requirement with a Medium VRF is consistent with the training Requirements in PER-005-1 and PER-005-2 that will become effective July 1, 2016.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: A VRF of Medium is consistent with the NERC VRF definition because GOP plant personnel could gain knowledge of the operational functionality of Protection Systems and Remedial Action Schemes that affect output of a generating Facility without specific training. It is unlikely that this requirement in the planning time frame, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, a violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This Requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

Proposed VSL – PER-006-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • one applicable personnel at a single Facility, or • 5% or less of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • two applicable personnel at a single Facility, or • more than 5% and less than or equal to 10% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • three applicable personnel at a single Facility, or • more than 10% and less than or equal to 15% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • five or more applicable personnel at a single Facility, or • more than 15% of the total applicable personnel of the Generator Operator. **OR** The Generator Operator failed to provide training as described in Requirement R1 to its applicable personnel.

VSL Justifications – PER-006-1, Requirement R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is a gradated VSL for partial performance from a Lower to High VSL and a VSL of Severe for severe or complete failure of the Requirement.

VSL Justifications – PER-006-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The currently effective PRC-001-1.1(ii) did not have VSLs assignments. The proposed VSLs do not lower the current level of compliance because they are consistent with the approved PER-005-2, Requirement R6 for which PER-006-1, Requirement R1 is based upon.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This Requirement has a binary component and utilizes a VSL of Severe for complete failure in addition to incremental VSLs for partial performance. The VSLs provide a non-preferential way to apply violation levels to both small and large entities. Violations may be assessed at the greater of the number of personnel at the plant level or a percentage of personnel at the entity level. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the corresponding Requirement, and is therefore consistent with the Requirement.

VSL Justifications – PER-006-1, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Exhibit G

Summary of Development History and Complete

Record of Development

Exhibit G-1

Summary of Development History and Record of Development for Project 2007-06 System Protection Coordination

Summary of Development History for Project 2007-06 System Protection Coordination

Summary of Development History

The development record for proposed Reliability Standard PRC-027-1 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team selected to lead each project in accordance with Section 4.3 if the NERC Standards Process Manual.[2] For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in **Exhibit H**.

II. Standard Development History

A. Standard Authorization Request Development

Project 2007-06 – System Protection Coordination was initiated on May 7, 2007 as a Standard Authorization Request ("SAR") to address the directive from FERC in Order No. 693,[3] and other issues identified by the System Protection and Control Task Force pertaining to PRC-001. The System Protection Coordination Standard Drafting Team ("SPC SDT") divided their project into two phases. In Phase 1 of the project, the SPC SDT addressed Requirements R3 and R4 of PRC-001.1(ii) and developed Reliability Standard PRC-027-1 to address outstanding issues in Project 2007-06. The SAR was approved by the Standards Committee and was posted for a 30-day informal comment period from June 11, 2007 through July 10, 2007.

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[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

[2] The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[3] Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*, 72 Fed. Reg. 16416 (2007) (to be codified at 18 C.F.R. pt. 40).

B. First Posting – Formal Comment Period, Ballot and Non-Binding Poll

Proposed Reliability PRC-027-1[4] was posted for a 45-day public comment period from May 21, 2012 through July 5, 2012, with an initial ballot held from June 26, 2012 through July 5, 2012. Several documents were posted for guidance with the first draft, including a Comment Form, Mapping Document, Implementation Plan, the Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") Justification document and the Technical Justification document. The initial ballot received 84.24% quorum, and 23.82% approval. The Non-binding Poll for VRFs and VSLs reached quorum at 82.26% of the ballot pool, and the standard and associated documents received support from 25.19% of the voters. There were 76 sets of responses to the posting, including comments from approximately 198 different individuals from approximately 139 companies representing all 10 of the industry segments.[5]

C. Second Comment Period, Successive Ballot and Non-Binding Poll

Proposed Reliability Standard PRC-027-1 was posted for an additional 30-day public comment period from November 16, 2012 through December 17, 2012, with a successive parallel ballot held from December 7, 2012 through December 17, 2012. The successive ballot reached quorum at 76.47% of the ballot pool, and the standard and associated documents received support from 33.23% of the voters. The Non-binding Poll reached quorum at 75.58% of the ballot pool, and the standard and associated documents received support from 34.80% of the voters. There were 82 sets of comments, including comments from approximately 220

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[4] The SPC SDT initially posted a draft of PRC-001-2 in 2009. After a second draft went through a NERC Quality Review in December 2010, the SPC SDT decided to focus its knowledge and expertise on developing a new results-based Reliability Standard.

[5] NERC, *Consideration of Comments*, Project 2007-06, System Protection Coordination, *available at* http://www.nerc.com/pa/Stand/Project%20200706%20System%20Protection%20Coordination%20DL/2007-06_C_of_C_11162012_Final_draft_ahm.pdf.

different individuals and approximately 157 companies, representing all 10 of the industry segments.[6]

D. Third Comment Period, Successive Ballot and Non-Binding Poll

Proposed Reliability Standard PRC-027-1 was posted for an additional 30-day formal comment period from June 4, 2013 through July 3, 2013, with an additional parallel ballot held from June 24, 2013 through July 3, 2013. The additional ballot reached quorum at 77.65% of the ballot pool, and the standard and associated documents received support from 52.71% of the voters. The Non-binding Poll reached quorum at 77.12% of the ballot pool, and the standard and associated documents received support from 52.48% of the voters. There were 67 sets of comments, including comments from approximately 196 different individuals and approximately 130 companies, representing all 10 of the industry segments.[7]

E. Fourth Comment Period, Additional Ballot and Non-Binding Poll

Proposed Reliability Standard PRC-027-1 was posted for an additional 45-day comment period from November 4, 2013 through December 31, 2013, with a successive parallel ballot held from December 9, 2013 through December 31, 2013. The successive ballot reached quorum at 76.60% of the ballot pool, and the standard and associated documents received support from 65.71% of the voters. The Non-binding Poll reached quorum at 77.63% of the ballot pool, and the standard and associated documents received support from 70.75% of the voters.

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6 NERC, *Consideration of Comments*, Project 2007-06 System Protection Coordination, *available at* http://www.nerc.com/pa/Stand/Project%20200706%20System%20Protection%20Coordination%20DL/Comment_Report_2007-06_SPCSDT_TEAM_final_05302013.pdf.

7 NERC, *Consideration of Comments*, Project 2007-06 System Protection Coordination PRC-027-1, *available at* http://www.nerc.com/pa/Stand/Project%20200706%20System%20Protection%20Coordination%20DL/Comment_report_2007-06_SPC_PRC-027_10312013_TEAM_final.pdf.

F. Fifth Comment Period, Additional Ballot and Non-Binding Poll

Proposed Reliability Standard PRC-027-1 was posted for an additional 45-day comment period from April 1, 2015 through May 15, 2015, with an additional parallel ballot held from May 6, 2015 through May 15, 2015. The additional ballot reached quorum at 82.53% of the ballot pool, and the standard and associated documents received support from 39.65% of the voters. The Non-binding Poll reached quorum at 81.65% of the ballot pool, and the standard and associated documents received support from 38.65% of the voters.

G. Sixth Comment Period, Additional Ballot and Non-Binding Poll

Proposed Reliability Standard PRC-027-1 was posted for an additional 45-day formal comment period from July 29, 2015 through September 11, 2015, with an additional parallel ballot held from September 2, 2015 through September 11, 2015. The additional ballot reached quorum at 84.34% of the ballot pool, and the standard and associated documents received support from 69.77% of the voters. The Non-binding Poll reached quorum at 82.22% of the ballot pool, and the standard and associated documents received support from 70.00% of the voters. There were 64 sets of comments, including comments from approximately 162 different individuals and approximately 112 companies, representing all 10 of the industry segments.[8]

H. Final Ballot

Proposed Reliability Standard PRC-027-1 was posted for a 10-day final ballot period from October 5, 2015 through October 14, 2015. The ballot for the proposed Reliability Standard and associated documents reached quorum at 89.16% of the ballot pool, and the

[8] NERC, *Consideration of Comments*, Project 2007-06 System Protection Coordination, (October 5, 2016), *available at* http://www.nerc.com/pa/Stand/Project%20200706%20System%20Protection%20Coordination%20DL/2007-06_System_Protection_Coordination_Comment_Report_10012015.pdf.

standard received sufficient affirmative votes for approval, receiving support from 80.94% of the voters.[9]

I. Board of Trustees Adoption

Proposed Reliability Standard PRC-027-1 was adopted by the NERC Board of Trustees on November 5, 2015.[10]

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[9] NERC, *Standards Announcement*, Project 2007-06 System Protection Coordination, *available at* http://www.nerc.com/pa/Stand/Project%20200706%20System%20Protection%20Coordination%20DL/2007-06_PRC-027-1_FB_Results_Word_Announc_10152015.pdf.

[10] NERC, *Board of Trustees Agenda Package*, Agenda Item 4e (Project 2007-06 System Protection Coordination (PRC-027)), *available at* http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Agenda_Package_November_2015_v3a.pdf.

Complete Record of Development for Project 2007-06 System Protection Coordination

Project 2007-06 System Protection Coordination

Related Files | 2007-06.2 Phase 2 of System Protection Coordination

Status:
A final ballot for **PRC-027-1 – Coordination of Protection Systems for Performance During Faults** concluded **8 p.m. Eastern, Wednesday, October 14, 2015.** The ballot results can be accessed via the links below. The standard will be submitted to the Board of Trustees for adoption. Once TOP-009-1 is approved by ballot and adopted by the Board of Trustees, PRC-027-1 will be filed with the appropriate regulatory authorities in conjunction with TOP-009-1 to achieve the complete retirement of PRC-001-1.1(ii).

Retirement of PRC-001-1.1(ii)
In conjunction with Project 2007-06.2 Phase 2 of System Protection Coordination, NERC is proposing the complete retirement of PRC-001-1.1(ii). In Phase 2, Requirement R1 is being incorporated into the proposed Reliability Standard TOP-009-1. Requirements R2, R5, and R6 are proposed for retirement as the reliability objectives of those requirements are addressed by other TOP/IRO standards. See the Mapping Document on the Phase 2 project page for an explanation of how the reliability objectives of Requirements R1, R2, R5, and R6 are addressed. The remaining two Requirements R3 and R4 of PRC-001-1.1(ii) are addressed by PRC-027-1. See the Project 2007-06 System Protection Coordination Mapping Document below. The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of Reliability Standards PRC-027-1 and TOP-009-1. NERC is proposing the retirement of PRC-001-1.1(ii) in the implementation plans associated with both projects.

Background
Project 2007-06 System Protection Coordination originated in 2007 to address directives from FERC Order 693 and other issues identified by the System Protection and Control Task Force pertaining to PRC-001. The System Protection Coordination Standard Drafting Team (SPCSDT) has developed Reliability Standard PRC-027-1 with the stated purpose: "*To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults*" to address all of the outstanding issues. PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii).

Draft 5 of PRC-027-1 was posted for formal comment and ballot from April 1 – May 15, 2015. The standard received affirmative votes totaling 39.63 percent. The drafting team appreciated the feedback industry stakeholders provided and has incorporated many of the suggested revisions into draft 6 of the standard. In accordance with section 4.13: Additional Ballots of the Standards Process Manual, the drafting team is not providing written responses to the comments with this posting because significant revisions to the standard were made and an Additional Ballot will be conducted.

Draft 6 of PRC-027-1 consists of three proposed requirements.

Requirement R1 mandates that an entity establish a process for developing new and revised Protection System settings for BES Elements to operate in the intended sequence during Faults; and stipulates certain attributes that must be included in the process.

Requirement R2 mandates that an entity periodically perform Protection System Coordination Studies and/or compare existing Fault current values to established Fault current baselines for Protection Systems applied on BES Elements that are identified as being affected by changes in Fault current. The applicable Protection System functions are identified in Attachment A.

Requirement R3 mandates that an entity utilize the process established in accordance with Requirement R1.

Standard(s) Affected: PRC-027-1 - System Protection Coordination, Retirement of PRC-001-1.1(ii) - System Protection Coordination

Purpose/Industry Need
Coordinated Protection Systems enhance reliability by isolating Faults, thus reducing the risk of BES instability or Cascading and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements removed from service and protect equipment from damage.

<table>
<tr><th>Draft</th><th>Action</th><th>Dates</th><th>Results</th><th>Consideration of Comments</th></tr>
<tr><td>Draft 6

PRC-027-1
Clean (117) | Redline to Last Posted (118)

Implementation Plan
Clean (119) | Redline to Last Posted (120)</td><td>Final Ballot

Info (121)

Vote</td><td>10/05/15 - 10/14/15</td><td>Summary (122)

Ballot Results (123)</td><td></td></tr>
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PRC-027-1
Clean (99) | Redline to Last Posted (100)

PRC-001-1.1 (ii)
Redline to Last Approved (101)

Implementation Plan
Clean (102) | Redline to Last Posted (103)

Supporting Materials

Unofficial Comment Form (Word) (104)

Mapping Document
Clean (105) | Redline to Last Posted (106)

VRF/VSL Justification
Clean (107)| Redline to Last Posted (108)

Draft RSAW</td><td>Additional Ballot and Non-binding Poll

Updated Info (109)

Info (110)

Vote</td><td>09/02/15 – 09/11/15</td><td>Summary (112)

Ballot Results (113)

Non-binding Poll Results (114)</td><td></td></tr>
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Info (111)

Submit Comments</td><td>07/29/15 – 09/11/15</td><td>Comments Received (115)</td><td>Consideration of Comments (116)</td></tr>
<tr><td>Info

Send RSAW feedback to:

RSAWfeedback@nerc.net</td><td>08/12/15 - 09/11/15</td><td></td><td></td></tr>
</table>

Draft 5 PRC-027-1 **(87)** Due to the extensive changes, a redline of PRC-027-1 is not included PRC-001-3 Clean | Redline Implementation Plan **(88)** **Supporting Materials** Unofficial Comment Form (Word) **(89)** Mapping Document **(90)** VRF/VSL Justification **(91)**	Additional Ballot and Non-binding Poll The ballot and non-binding poll for this posting are **additional**. Since the previous ballot pools for this project are outdated, new ballot pools are being formed in the SBS. Updated Info **(92)** Info **(93)** Vote	05/06/15 - 05/15/15	Summary **(95)** Additional Ballot Results **(96)** Non-binding Poll Results (Updated) **(97)**	
	Comment Period Info **(94)** Submit Comments	04/01/15 - 05/15/15	Comments Received **(98)**	
	Join Ballot Pools If you had previously joined the ballot pools for PRC-027-1, you **must** join these ballot pools to cast a vote. Previous PRC-027-1 ballot pool members **will not** be carried over to these ballot pools.	04/01/15 - 04/30/15		
Draft RSAWs	Info	04/16/15 - 05/15/15		

PRC-027-1 PRC-001-3	Send RSAW feedback to: RSAWfeedback@nerc.net			
Preliminary Draft 5 PRC-027-1 **(83)** **Supporting Materials** Unofficial Comment Form (Word) **(84)**	Informal Comment Period Info **(85)** Submit Comments	10/01/14 - 10/21/14	Comments Received **(86)**	
Draft 4 PRC-027-1 Standard Clean **(67)** / Redline to last posting **(68)** Implementation Plan Clean **(69)** / Redline to last posting **(70)** **Supporting Materials** Unofficial Comment Form (Word) **(71)** Mapping Document Clean **(72)** / Redline to last posting **(73)** VRF/VSL Justification Clean **(74)** / Redline to last posting **(75)** PRC-001-3 Clean with Roadmap / Redline with Roadmap	Additional Ballot and Non-Binding Poll Updated Info **(76)** Info **(77)** Vote	12/9/13 - 12/31/13	Summary **(79)** Ballot Results **(80)** Non-Binding Poll Results **(81)**	
	Comment Period Info **(78)** Submit Comments	11/4/13 - 12/31/13	Comments Received **(82)**	
Draft 4 PRC-027-1 Standard Clean **(54)** / Redline to last posting **(55)**	Additional Ballot and Non-binding Poll Updated Info **(63)**	10/23/13 - 11/1/13 This ballot has been postponed as of September 27, 2013.		

Implementation Plan Clean **(56)** / Redline **(57)** **Supporting Materials** Unofficial Comment Form (Word) **(58)** Mapping Document Clean **(59)** / Redline **(60)** VRF/VSL Justification Clean **(61)** / Redline **(62)**	Info **(64)** Vote			
	Comment Period Updated Info **(65)** Info **(66)** Submit Comments	09/18/13 - 11/1/13 This comment period has ended as of September 27, 2013.		
Draft 3 PRC-027-1 Standard Clean **(37)** / Redline to last posting **(38)** Redline to last posting **(39)** (Updated 6/6/13 to correct overlapping text boxes) **Supporting Materials** Unofficial Comment Form (Word) **(40)** Mapping Document Clean **(41)** / Redline **(42)** Implementation Plan Clean **(43)** / Redline **(44)** VRF/VSL Justification Clean **(45)** / Redline **(46)** PRC-001-3 Clean / Redline	Successive Ballot and Non-binding Poll Updated Info **(47)** Vote	06/24/13 - 07/03/13	Summary **(49)** Ballot Results **(50)** Non-binding Poll Results **(51)**	
	Comment Period Info **(48)** Submit Comments	06/04/13 - 07/03/13	Comments Received **(52)**	Consideration of Comments **(53)**

Draft 2 PRC-027-1 Standard Clean **(22)** | Redline to last posting **(23)** **Supporting Materials** Comment Form (Word) **(24)** Mapping Document **(25)** Implementation Plan Clean **(26)** | Redline **(27)** VRF/VSL Justification **(28)** PRC-001-3 Clean | Redline	Successive Ballot and Non-binding Poll Updated Info **(29)** Info **(30)** Vote	12/7/2012 - 12/17/2012	Summary **(32)** Ballot Results **(33)** Non-binding Poll Results **(34)**	
	Comment Period Info **(31)** Submit Comments	11/16/2012 - 12/17/2012	Comments Received **(35)**	Consideration of Comments **(36)**
Draft 1 PRC-027-1 Standard Clean **(9)** **Supporting Materials** Comment Form (Word) **(10)** Mapping Document **(11)** Implementation Plan **(12)** VRF/VSL Justification **(13)** Technical Justification **(14)** PRC-001-3 (updated 5/31/12) Clean | Redline	Initial Ballot and Non-binding Poll Info **(15)** Vote	6/26/2012 - 7/05/2012	Summary **(17)** Ballot Results **(18)** Non-binding Poll Results **(19)**	
	Comment Period Info **(16)** Submit Comments	5/21/2012 - 7/5/2012	Comments Received **(20)**	Consideration of Comments **(21)**
	Join Ballot Pools	5/21/2012 - 6/19/2012		
Draft 1 PRC-001-2 Standard	Comment Period Info	9/11/2009 - 10/26/2009	Comments Received	Consideration of Comments

PRC-001-2 Implementation Plan **Supporting Materials** Comment Form (Word) PRC-001-2 Reference Document	Submit Comments			
Drafting Team Nominations	Info **(8)** Submit Nomination	8/15/2007 - 8/29/2007		
Final SAR Clean **(6)** | Redline **(7)**				
Draft SAR Version 1 System Protection Coordination Draft SAR Version 1 **(1)** **Supporting Materials** NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination **(2)**	Comment Period Info **(3)** Submit Comments	6/11/2007 - 7/10/2007	Comments Received **(4)**	Consideration of Comments **(5)**

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard **PRC-001-1 — System Protection Coordination (Project 2007-06)**	
Request Date	May 7, 2007

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)
Name NERC System Protection and Control Task Force (Attachment A)	☐	New Standard
Primary Contact Charles Rogers (SPCTF Chairman)	☒	Revision to existing Standard
Telephone 517-788-0027 Fax 517-788-0917	☐	Withdrawal of existing Standard
E-mail cwrogers@cmsenergy.com	☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

The purpose of standard PRC-001-1 — System Protection Coordination should remain "To ensure system protection is coordinated among operating entities." The standard should be revised to:

1. Assure that Protection System application and performance issues are coordinated among all related entities.
2. Correct the applicable entities within the standard to reflect the actual functional responsibilities, as described in the NERC Functional Model.
3. Incorporate other general improvements described in the standards development work plan and from other sources.
4. Address directives received from ERO regulatory authorities.
5. Consider the observations and recommendations developed by the NERC SPCTF, which are detailed in the attached report (Attachment B), approved by the Planning Committee in December 2006.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

Protection system coordination is an absolute necessity for the North American electric system to operate properly. PRC-001 is a Version 0 standard, and was translated from an operating policy that was appropriate in an era of voluntary compliance.

The Version 0 standards and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update those standards, incorporating improvements to make the standards more suitable for enforcement.

Both FERC (within Order 693) and the SPCTF (in their report on PRC-001) identified significant shortcomings in the existing standard.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

The existing PRC-001 Standard has been identified in the Reliability Standards Development Plan as requiring revision, within the FERC Order 693 as requiring revisions, and by a SPCTF report (attached) which identified a number of issues with the existing standard (the SPCTF report, which precedes FERC Order 693, also includes observations from the preceding FERC NOPR on RM-06-16-000). This revision of PRC-001 should address concerns from these sources and should include the upgrades to the standard identified in Attachment C to bring the revised standard into conformance with the latest version of the ERO Rules of Procedure.

Detailed Description

This project will address the issues identified by the System Protection and Control Task Force for the planning-related requirements in PRC-001 as well as any planning-related concerns identified in FERC Order 693. (The operations-related requirements in PRC-001 are being addressed under Project 2006-06.) A detailed listing of the areas of the existing standard that need improvement is provided in Attachment B titled "NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination"

The drafting team will also make the improvements to the standard identified in Attachment C – "Reliability Standards Review Guidelines" to bring the revised standard into conformance with the latest version of the ERO Rules of Procedure.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☒	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes

5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
MOD-011-0	Modify to include the essential data for wide-area fault studies, as noted in the attached SPCTF report on PRC-001.

Related SARs

SAR ID	Explanation
RC SAR	Project 2006-06 – Reliability Coordination includes modification of the real-time requirements but does not address the planning-related requirements.

Regional Variances

Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
SERC	None
RFC	None
SPP	None
WECC	None

NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination

December 7, 2006

A Technical Review of Standards

Prepared by the
System Protection and Controls Task Force
of the
NERC Planning Committee

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Appendix B — SYSTEM PROTECTION AND CONTROL TASK FORCE **9**

This report was approved by the Planning Committee on December 7, 2006, for forwarding to the Standards Committee.

Introduction

When the original scope for the System Protection and Control Task Force was developed, one of the assigned items was to review all of the existing PRC-series Reliability Standards, to advise the Planning Committee of our assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.

This report presents the SPCTF's assessment of PRC-001-0 – System Protection Coordination. The report includes the SPCTF's understanding of the intent of this standard and contains specific observations relative to the existing standard.

This standard was developed by translating the requirements of an earlier Phase I Planning Standard; thus it has not been previously subjected to a critical review of the Requirements.

Executive Summary

This reliability standard is intended to assure that system protection is coordinated between multiple transmission entities and between generation entities and transmission entities. It appears that this standard is intended to address coordination of protection functions and capabilities in both the operating time frame and the planning time frame. These time frames, as they apply to protective functions, are discussed, as are the various responsibilities to assure the related coordination.

The SPCTF concludes that the list of applicable entities in the existing standard is incomplete and that the assigned responsibilities do not reflect the activities of the identified functions. Significantly, the existing standard disregards the significant responsibilities and roles of the equipment owners; specifically, the Transmission Owners and Generator Owners.

The SPCTF also concludes that the Requirements of the existing standard are vague and ambiguous, and that, while Measures and Levels of Non-Compliance are defined, these are essentially unenforceable because of fundamental flaws within the requirements.

Assessment of PRC-001-0

General Comments

The SPCTF offers the following general comments:

1. None of the requirements within PRC-001-0 specifically indicate what protective systems are being addressed.
2. The phrase "protective relay or equipment" is a recurring phrase, and generally should be revised to "protective system" or "protective system equipment."
3. The phrase "If a protective relay or equipment failure reduces system reliability" is ambiguous, and needs additional clarification. This phrase does not clearly state when failures must be reported.
4. Many of the requirements list the Balancing Authority as an applicable entity. It does not seem that the Balancing Authority has the direct responsibility for any of these activities, and only needs to respond to the various issues when directed by the Transmission Operator and/or Generator Operator.

Applicability

4.1. Balancing Authorities
4.2. Transmission Operators
4.3. Generator Operators

The remainder of the PRC-series standards rarely assigns any responsibility for protection systems to any of the above entities. Specifically, the responsibilities for disturbance monitoring (which includes some monitoring of protective systems) and for protective system maintenance apply to the equipment owners, specifically Transmission Owners and Generator Owners. The current applicable entities do, however, have a role in the functions of this standard. The SPCTF asserts that Transmission Owner, Generator Owner, and Distribution Provider should be added to the list of Applicable Entities.

R1

> **R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protective system schemes applied it its area.

This requirement is a statement of a highly laudable goal, but this is not specific and enforceable. In fact, the drafting team that was providing missing Measures and Compliance Elements was unable to assign either to this requirement.

It may be possible to restate this requirement in such a way to be measurable and enforceable. The protective system equipment owners (Transmission Owners, Generator Owners, and Distribution Providers) should be responsible to provide the necessary information to the Transmission Operator and Generator Operator to facilitate their familiarity with the relevant protective systems.

R2

> **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
>
> ~~R2.1.~~If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
>
> ~~R2.2.~~If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

Requirement R2 addresses the operating horizon, but the equipment owner entities will be familiar with the condition of their protective system equipment.

Therefore, the responsibility for this requirement must originate with the owner entities: the Transmission Owner, Generator Owner, and Distribution Provider. These entities should inform the Transmission Operator, Generator Operator, and Balancing Authorities of equipment failures pertinent to this requirement. The Transmission Operators may need to have to coordinate with each other, similar to the existing requirement R4.

The requirement for corrective action, “as soon as possible”, is vague and ambiguous, and needs modification to be specific.

As evidenced by the lack of a related Measure (via the drafting team for missing Measures and Compliance Elements), this requirement is currently not measurable.

R3

Not only new protective systems and changes to protective systems should be coordinated. A

> **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
>
> **R3.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
>
> **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

requirement should be added to require coordination of all existing protective systems. Then, requirement R3 should require the coordination new protective systems and changes to protective systems with existing protective systems.

Requirement R3 addresses the planning horizon; therefore, this responsibility should be assigned to the Transmission Owner, Generator Owner, and Distribution Provider.

In addition, R3.1 should be bi-directional; the Transmission entity should provide similar coordination with the Generator entity.

R4

> **R4.** Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

It's unclear whether this requirement addresses the operations planning horizon or the planning horizon.

If Requirement R4 addresses the planning horizon, the responsibilities should be assigned similarly to the recommendations for R3, to the Transmission Owner, Generator Owner, and Distribution Provider. If Requirement R4 addresses the planning horizon, it seems to be redundant with R3 to some extent.

R5

> **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:
>
> **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.
>
> **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.

Requirement R5 addresses the both the planning horizon and operating planning horizon. It is essential to the reliability of the system that this activity occurs, and it must occur in advance of any changes to the system.

In the operations planning horizon, the Operator entities should coordinate these changes with the Owner entities, since the Owners have the tools to analyze the effects of these system changes on the protective systems and the access to the protective systems to make any needed changes to the protective system.

In the planning horizon, the owner entities should be responsible for this requirement, similarly to Requirement R3.

R6

R6.	Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

Requirement R6 addresses the operating horizon. The Owners have to monitor the status of Special Protection Systems and provide the status to the Operators. The Operators then should coordinate the availability of Special Protection Systems between each other, and take any necessary operating actions to address issues with Special Protection Systems.

This requirement needs to better define "status of … Special Protection System…"

This requirement may be better moved to one of the PRC-series standards specifically addressing Special Protection Systems.

Related Standard
MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
Also, while reviewing PRC-001, the SPCTF noted that no existing NERC Standard requires that a consistent model be maintained for protection studies, such as that required by MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures, for other steady-state studies. Without such a model, various Transmission Owners, Generator Owners, and Distribution Providers cannot accurately apply the protective relaying. To address this deficiency, the SPCTF recommends that MOD-011, Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures, be modified to include the essential data for wide-area fault studies. The specific MOD-011 requirements are listed below, together with suggested modifications.

R1.2 – Generators
Recommend including direct-axis synchronous reactance (X_d), transient reactance (X_d'), sub transient reactance (X_d"), and the associated time constants (T_{do}, T_{do}', and T_{do}") for synchronous generators. For induction and inverter generators, generically include the data necessary to model the equipment in short circuit models in the positive, negative, and zero sequence domains.

R1.3 – Transmission Lines
Recommend specifying the positive and zero sequence impedance, including mutual impedances

R1.5 – Transformers
Recommend specifying positive sequence and zero sequence impedance, including all grounding effects.

FERC Assessment of PRC-001-0

In the October 20, 2006, the Notice of Proposed Rulemaking for adoption of NERC Standards (Docket Number RM06-16-000), the Federal Energy Regulatory Commission, for the most part, considered the operating horizon impacts of PRC-001. FERC proposed that PRC-001-0 be approved as mandatory and enforceable. They did, however, propose that NERC be directed to make modifications to PRC-001. The modifications proposed in the NOPR are excerpted from the NOPR and repeated below:

> "The Commission proposes to direct that NERC submit a modification to PRC-001-0 that: (1) includes Measures and Levels of Non-Compliance; (2) includes a requirement that relevant transmission operators and generator operators must be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities can carry out the appropriate corrective control actions consistent with those used in mitigating IROL violations; and (3) clarifies that, after being informed of failures in relays or protection system elements on the Bulk-Power System, transmission operators or generator operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes."

Other Activities related to PRC-001-0

The Standard Drafting Team on Missing Measures and Compliance Elements modified PRC-001-0 as a part of their work, but the requirements were not changed. As this report is being prepared, the modified Standard is being balloted.

A draft SAR for the revision of PRC-001-0 is included in the "Draft Reliability Standards Development Plan: 2007–2009", which was presented to the NERC Board of Trustees for their approval on November 1, 2006. This draft SAR is entitled, "System Protection Project (2009-01)", and discusses many of the same deficiencies in PRC-001-1 that were identified by the SPCTF.

Conclusion and Recommendation

As it exists today, enforcement of PRC-001-0 will be very difficult. The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the "operating horizon," "operations planning horizon," and "planning horizon" protection coordination issues, the deficiencies in the current standard are magnified.

The SPCTF recommends that the existing draft Standards Authorization Request that is included in the "Draft Reliability Standards Development Plan: 2007–2009" be modified to include the observations from the SPCTF assessment of PRC-001-0 and also include the modifications directed in the FERC NOPR on RM06-16-000. The SPCTF also recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards.

In addition, it is not possible to effectively coordinate protective systems without having accurate short circuit models of neighboring systems. To address these modeling issues related to data for short circuit calculations, the SPCTF recommends that a Standards Authorization Request be developed to modify Standard MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures, to address these issues. Data for short circuit calculations, as noted in this report, should be considered as additional requirements within MOD-013-1.

Appendices

Attachment A is not relevant to this SAR and was removed

Appendix B — SYSTEM PROTECTION AND CONTROL TASK FORCE

Charles W. Rogers
Chairman / RFC-ECAR Representative
Principal Engineer
Consumers Energy Co.

W. Mark Carpenter
Vice Chairman / ERCOT Representative
System Protection Manager
TXU Electric Delivery

John Mulhausen
FRCC Representative
Manager, Design and Standards
Florida Power & Light Co.

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W. O. (Bill) Kennedy
Canada Member-at-Large
Principal
b7kennedy & Associates Inc.

Bob Stuart
NERC Blackout Investigation Team
Director of Business Development, Principal T&D Consultant
Elequant, Inc.

Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replace existing 'levels of non-compliance.') The violation severity levels must be applied for each requirement and may be combined to cover multiple requirements, as long as it is clear which requirements are included and that all requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: more than 95% but less than 100% compliant.
- **Moderate: mostly compliant with significant exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: more than 85% but less than or equal to 95% compliant.
- **High: marginal performance or results** — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: more than 70% but less than or equal to 85% compliant.
- **Severe: poor performance or results** — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: 70% or less compliant.

Compliance Monitor
Replace, 'Regional Reliability Organization' with 'Regional Entity'

Fill-in-the-blank Requirements
Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan. The effective date should be linked to the NERC BOT adoption date.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Functional Model Version 3
Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Maureen E. Long
Standards Process Manager

June 11, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Comment Periods Open

The Standards Committee (SC) announces the following standards actions:

SAR for System Protection Coordination (Project 2007-06) Posted for 30-day Comment Period June 11–July 10, 2007

The SAR for Project 2007-06 — System Protection Coordination proposes to address the FERC directives in Order 693 and to address a number of technical shortcomings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

The purpose of the proposed standard is to assure that protection system application and performance issues are coordinated among all related entities. Please use this comment form to submit comments on this SAR.

SAR for Protection System Maintenance & Testing (Project 2007-17) Posted for 30-day Comment Period June 11–July 10, 2007

This SAR for Project 2007-17 — Protection System Maintenance and Testing proposes to merge the requirements from the following standards into a single standard to reduce the costs of compliance while also improving efficiencies:

- PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs
- PRC-011-0 — UVLS System Maintenance and Testing
- PRC-017-0 — Special Protection System Maintenance and Testing

The SAR also proposes to address the FERC directives in Order 693 and to address a number of technical shortcomings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

The purpose of the proposed standard is to ensure all transmission and generation protection systems affecting the reliability of the bulk power system are maintained and tested to support reliable operation performance when responding to abnormal system conditions. Please use this comment form to submit comments on this SAR.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Robert J. Rauschenbach	
Organization:	Ameren	
Telephone:	314-554-3535	
E-mail:	rrauschenbach@ameren.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR proposes to improve and expand upon the requirements in PRC-001 — System Protection Coordination. Note that some of the requirements in PRC-001 involve real-time control actions taken by entities other than the facility owners, and these requirements may be moved from PRC-001 into Project 2006-06 — Reliability Coordination.

The SAR proposes to address the FERC directives in Order 693 and to address a number of technical short comings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

Please review the SAR and then answer the questions on the following page. Please e-mail your comments on this form to sarcomm@nerc.net with the subject "Protection Maintenance SAR" by **July 10, 2007**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: None
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: No
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: Development of intercompany short circuit modeling should be cover in a separte MOD standard. Maintaining one large overall regional short circuit model is neither practical nor necessary. Standard methods to exchange short circuit data of tie-line plus one breakered bus into the neighboring systems should be adeqaute and be developed. Otherwise Ameren agrees with SPCTF recommendations.

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Individual Commenter Information

(Complete this page for comments from one organization or individual.)

Name:	Thad K. Ness
Organization:	American Electric Power (AEP)
Telephone:	614-716-2053
E-mail:	tkness@aep.com

NERC Region		Registered Ballot Body Segment
☒ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☒ RFC	☒	5 — Electric Generators
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☒ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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The SAR proposes to address the FERC directives in Order 693 and to address a number of technical short comings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

Please review the SAR and then answer the questions on the following page. Please e-mail your comments on this form to sarcomm@nerc.net with the subject "Protection Maintenance SAR" by **July 10, 2007**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☐ Yes

   ☒ No

   Comments: There might not be a directly reliability driver for improving this standard, but the standard should be improved to better clarify responsibilities.

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: None
   Comments: None

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: Possibly
   Comments: AEP and other utilities, with many years of experience serving customers and supporting the electric grid, have voluntarily integrated protection coordination processes into the core of their work practices . AEP fully supports improvements if they truly foster reliability and availability benefits to bulk power transfers. More Standards, Requirements, and Business Practices are not always better. If Standards create burdens on a utility's physical resources and budgets, then some mechanism must be available to allow for the needed changes.

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: For clarifying protective systems, the standard should not use the term Bulk Electric System, but should instead specify a voltage threshold for impacts to bulk system transfers - specifically; 'Facilites operated 200 kV and above and Regionally-defined, Operationally Significant facilities operated greater than 100 kv, but less than 199 kV'. The term 'affects' also needs to be clarified. Inclusion of all facilities greater than 100 kV does not benefit the reliability of national bulk power transfers. For example, the loss or misoperation of a 138 kV line serving a localized load center would not be detremental to bulk power transfers multiple busses away.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: Jason Shaver		
Organization: American Transmission Co.		
Telephone: 262 506 6885		
E-mail: jshaver@atcllc.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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The SAR proposes to address the FERC directives in Order 693 and to address a number of technical short comings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

Please review the SAR and then answer the questions on the following page. Please e-mail your comments on this form to sarcomm@nerc.net with the subject "Protection Maintenance SAR" by **July 10, 2007**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments: Standard has much room for improvement.

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments: Moving R6 regarding SPS monitoring and status notification to more appropriate PRC SPS section makes sense.

   Have concern about NERC SPCTF recommendation of merging system short-circuit databases for perfoming wide-area fault studies. See additional comments below.

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: Data entry and maintenance procedures for proposed wide-area short circuit model would need to be developed.
   Comments: Creating and maintaining the proposed wide-area short-circuit database, although useful, might prove quite difficult to implement.

   Among our concerns:

Impedance units- Ohms or per unit? If per unit, using what common base?

CAPE to ASPEN & ASPEN to CAPE conversion issues?

Need for unique and consistent bus numbers for all busses in combined database.

If using CAPE, coordination and application of database categories.

Who would be responsible for merging the databases and then maintaining the common database? How often would the databases be remerged to reflect system changes?

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: Background Information Section on this comment sheet should read:

   Please e-mail your comments on this form to sarcomm@nerc.net with subject "Protection Coordination SAR" in subject line, not "Protection Maintenance SAR" as stated.

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Dean Bender	
Organization:	Bonneville Power Administration	
Telephone:	(360) 418-2040	
E-mail:	dabender@bpa.gov	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments: No known variance

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Nancy C. Denton	
Organization:	Consumers Energy Company	
Telephone:	517-788-1310	
E-mail:	ncdenton@cmsenergy.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: N/A
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: N/A
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: None.

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Doug Hohlbaugh
Organization:	FirstEnergy
Telephone:	330-384-4698
E-mail:	hohlbaughdg@firstenergycorp.com

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
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Group Comments (Complete this page if comments are from a group.)

Group Name:	FirstEnergy
Lead Contact:	Doug Hohlbaugh
Contact Organization:	
Contact Segment:	
Contact Telephone:	330-384-4698
Contact E-mail:	hohlbaughdg@firstenergycorp.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Art Buanno	FE, Tranmission Planning & Protection	RFC	1
Bob McFeaters	FE, Tranmission Planning & Protection	RFC	1
Bill Duge	FE, Nuclear Generation	RFC	5
Ken Dresner	FE, Fossil Generation	RFC	5

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☐ Yes

   ☒ No

   Comments: Under the section of Detailed Description it is stated:

   "This project will address the issues identified by the System Protection and Control Task Force for the planning-related requirements in PRC-001 as well as any planning-related concerns identified in FERC Order 693. (The operations-related requirements in PRC-001 are being addressed under Project 2006-06.) A detailed listing of the areas of the existing standard that need improvement is provided in Attachment B titled "NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination"

   It seems that it would be more effective to pull the PRC-001 standard from the scope of of the 2006-06 project which deals with mulitple standards and allow this SDT to focus on all aspects of the PRC-001. The SPCTF raised concerns with PRC-001 in both the planning and operations time-frame and it does not appear that the 2006-06 project is scoped to address the SPCTF items.

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☐ Yes

   ☒ No

   Comments: FE agrees with the SPCTF that the TO, GO and DP should be added to the applicability section of this standard as many of the requirements will originate from these entities. However, it may be necessary to to add the Tranmission Planner (TP) entity for "planning" related requirements. For example, the existing R3 requires coordination of new or revised protections systems. It may be short-sighted to assume that the TO is the entity who would coordinate this work; there may be situations where a Transmission Planner performs this work and is best suited to share the information with neighboring system owners/planners as well as the Planning Coordinator.

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments: Aware of none

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments: Aware of none

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: none

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
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NERC Region		**Registered Ballot Body Segment**
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Group Comments (Complete this page if comments are from a group.)

Group Name: FRCC

Lead Contact: Eric Senkowicz

Contact Organization: FRCC

Contact Segment: 10

Contact Telephone: 813-207-7980

Contact E-mail: esenkowicz@frcc.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Alan Gale	City of Tallahassee	FRCC	5

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☒ No

   Comments: Incorporating assessments by subject matter experts such as this NERC SPCTF / Planning Committee assessment into the NERC Standards revision SAR project is an efficient way to supplement project SARs and allows for valuable input at the front-end of the standards process.

   Attachments A and C are not included in the SAR and Attachment B is identified as "Supporting Material". It may be clearer to include all applicable documents within the SAR including including relevant excerpts from any FERC assessmentss and requested changes to the standard.

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☐ Yes

   ☐ No

   Comments: This question may be better addressed as the standard is drafted.

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: The Drafting team should coordinate any system protection terminology introduced or re-defined within this standard with other system protection related SARs (i.e. Distrurbance monitoring, System Protection Maintenance and Testing) to ensure common terminology is appropriately defined in the standards glossary.

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Individual Commenter Information

(Complete this page for comments from one organization or individual.)

Name:	Roger Champagne
Organization:	Hydro-Québec TransÉnergie
Telephone:	514 289-2211, X 2766
E-mail:	champagne.roger.2@hydro.qc.ca

NERC Region		Registered Ballot Body Segment
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☒ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☐ Yes

   ☒ No

   Comments: recommend that Transmission Planners be added

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments: No Regional Variance

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments: No Business Practice

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: none

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Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name:	Ron Falsetti	
Organization:	IESO	
Telephone:	905-855-6187	
E-mail:	ron.falsetti@ieso.ca	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☒ No

   Comments: It is not clear based on the information presented how all the functional entities are involved. As an example, no reference is noted in the documents for PC responsibility. Is it inferred that if a coordination model is developed on a wide area basis, the PC will be the responsible entity?

   Functional Model entity definitions, tasks, and obligations must be followed while developing applicability of the requirements.

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments:
   The IESO commends NERC, the SDT and the SPCTF (White Paper) for providing clarifications and improvements in the system protection areas.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: IRC Standards Review Committee

Lead Contact: Charles Yeung

Contact Organization: SPP

Contact Segment: 2

Contact Telephone: 832-724-6142

Contact E-mail: cyeung@spp.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Jim Castle	NYISO	NPCC	2
Alicia Daugherty	PJM	RFC	2
Ron Falsetti	IESO	NPCC	2
Matt Goldberg	ISO-NE	NPCC	2
Brent Kingsford	CAISO	WECC	2
Anita Lee	AESO	WECC	2
Steve Myers	ERCOT	ERCOT	2
William Phillips	MISO	RFC+MRO+SERC	2

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☒ No

   Comments: It is not clear based on the information presented if all the functional entities involved are identified in the scope of the standard. As an example, no reference is noted in the documents for TP responsibility. It is inferred that if a coordination model is developed on a wide area basis, the PC will be the only responsible entity. However there may be requirements for the TP as well.

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments:

1. The SRC commends NERC, the SDT and the SPCTF for providing this clarification and improvements in the system protection areas.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Walter Marusenko	
Organization:	Manitoba Hydro	
Telephone:	204-487-5407	
E-mail:	wmarusenko@hydro.mb.ca	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments: No comments.

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments: No comments.

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments: No comments

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: None.
   Comments: No variance necessary.

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: None.
   Comments: No comments.

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: No comments.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Midwest Reliability Organization (MRO)

Lead Contact: Joe Knight

Contact Organization: **MRO for Group (GRE - for lead contact)**

Contact Segment: 10

Contact Telephone: 763.241.5633

Contact E-mail: jknight@grenergy.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Neal Balu	WPS	MRO	10
Terry Bilke	MISO	MRO	10
Robert Coish, Chair	MHEB	MRO	10
Carol Gerou	MP	MRO	10
Ken Goldsmith	ALT	MRO	10
Jim Haigh	WAPA	**MRO**	10
Tom Mielnik	MEC	MRO	10
Pam Oreschnick	XEL	MRO	10
Dave Rudolph	BEPC	MRO	10
Eric Ruskamp	LES	MRO	10
MIke Brytowski, Secretary	MRO	MRO	10
28 Additional MRO Members	Not Named Above	MRO	10

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: None
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: None
   Comments:

6. If you have any other comments on this SAR that you haven’t provided above, please provide them here.

   Comments:
   1. The MRO commends NERC and the SDT for taking the necessary steps to remove the vagueness and ambiguity in the requirements; as well as the need to have clarity and measurability now that the industry has transitioned to mandatory and enforceable standards.

2. The SPCTF Assessment of PRC-001-1 did not mention how they would address "Corrective Actions" listed in R2. The MRO requests that the SDT expand on what the scope of these "Corrective Actions" is meant to be (e.g. real-time, or after the fact repair or replacement of defective equipment).

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:	Public Service Commission of South Carolina
Lead Contact:	Phil Riley
Contact Organization:	Public Service Commission of South Carolina
Contact Segment:	9
Contact Telephone:	803-896-5154
Contact E-mail:	philip.riley@psc.sc.gov

Additional Member Name	Additional Member Organization	Region*	Segment*
Mignon L. Clyburn	Public Service Commission of SC	SERC	9
Elizabeth B. "Lib" Fleming	Public Service Commission of SC	SERC	9
G. O'Neal Hamilton	Public Service Commission of SC	SERC	9
John E. "Butch" Howard	Public Service Commission of SC	SERC	9
Randy Mitchell	Public Service Commission of SC	SERC	9
C. Robert "Bob" Moseley	Public Service Commission of SC	SERC	9
David A. Wright	Public Service Commission of SC	SERC	9

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1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments: N/A

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments: N/A

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: N/A

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Individual Commenter Information

(Complete this page for comments from one organization or individual.)

Name:	Mike Gentry
Organization:	Salt River Project
Telephone:	602-236-6408
E-mail:	Mike.Gentry@srpnet.com

NERC Region		Registered Ballot Body Segment
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

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Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments:

6. If you have any other comments on this SAR that you haven’t provided above, please provide them here.

   Comments: I am concerned with the language proposed by FERC and the comparison to reactions to IROL's. Will FERC's requirement apply to a single protection system that has a redundant protection system? Will FERC's requirement apply to a system that is in an "overexposed" state? Will FERC's requirement apply to a system that may be exposed to slow 30 cycle of less tripping. These conditions must be identified in detail as to what will need to meet the "returning the system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes." FERC requirement

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: SERC EC Protection & Control Subcommittee (PCS)

Lead Contact: Jay Farrington

Contact Organization: Alabama Electric Cooperative, Inc.

Contact Segment: 1

Contact Telephone: (334) 427-3225

Contact E-mail: jay.farrington@powersouth.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Robert Rauschenbach	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
Jammie Lee	Entergy	SERC	1
Tom Seeley	E.ON-U.S.	SERC	1
Steve Waldrep	Georgia Power Company	SERC	1
Hong-Ming Shuh	Georgia Transmission Corporation	SERC	1
Neal Jones	Georgia Transmission Corporation	SERC	1
Jerry Blackley	Progress Energy Carolinas	SERC	1
Pat Huntley	SERC Reliability Corp.	SERC	10
Marion Frick	South Carolina Electric & Gas Co.	SERC	1
Bridget Coffman	South Carolina Public Service Authority	SERC	1
George Pitts	Tennessee Valley Authority	SERC	1
Meyer Kao	Tennessee Valley Authority	SERC	1
Phil Winston	Georgia Power Company	SERC	1
Ernesto Paon	Municipal Electric Authority of Georgia	SERC	1

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR proposes to improve and expand upon the requirements in PRC-001 — System Protection Coordination. Note that some of the requirements in PRC-001 involve real-time control actions taken by entities other than the facility owners, and these requirements may be moved from PRC-001 into Project 2006-06 — Reliability Coordination.

The SAR proposes to address the FERC directives in Order 693 and to address a number of technical short comings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

Please review the SAR and then answer the questions on the following page. Please e-mail your comments on this form to sarcomm@nerc.net with the subject "Protection Maintenance SAR" by **July 10, 2007**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☐ Yes

   ☒ No

   Comments: Consideration should be given to splitting this effort among 2 or 3 standards to address the operating, operations planning, and planning horizons. Consideration should also be given to moving the operating training requirements to another standard (if not already covered by an existing standard).

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments: The requirements for the PC, TO, GO, and DP (planning horizon) should be in a separate standard than those for the RC, BA, TOP, and GOP (operating and operations planning horizons).

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: none
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: none
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

Comments: none

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:	Southwest Transmission Cooperative, Inc.
Lead Contact:	E. William Riley
Contact Organization:	Southwest Transmission Cooperative, Inc.
Contact Segment:	**1**
Contact Telephone:	520-586-5440
Contact E-mail:	briley@swtransco.coop

Additional Member Name	Additional Member Organization	Region*	Segment*
Tom D. Spence, P.E	Southwest Transmission Coop., Inc.	**WECC**	1

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR proposes to improve and expand upon the requirements in PRC-001 — System Protection Coordination. Note that some of the requirements in PRC-001 involve real-time control actions taken by entities other than the facility owners, and these requirements may be moved from PRC-001 into Project 2006-06 — Reliability Coordination.

The SAR proposes to address the FERC directives in Order 693 and to address a number of technical short comings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

Please review the SAR and then answer the questions on the following page. Please e-mail your comments on this form to sarcomm@nerc.net with the subject "Protection Maintenance SAR" by **July 10, 2007**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments: We agree that there is a need to improve the requirements of Standard PRC-001-0 and Standard MOD-011-0 as described in the supplemental document "NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination". It is important to modify ambiguous statements such as "...corrective action needs to be taken..." and "must be done...as soon as possible...". By making the improvements described in the SAR, the standard will provide the applicable entities with more definitive requirements that will allow entities to provide specific responsibilities to internal work groups within the standard utility organization.

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments: Another important change described in this SAR is the requirement to have an up-to-date accurate model of the transmission system for protection studies. It is extremely important to develop these accurate models to allow enhance the reliability of the bulk-electric system. There are efforts underway in the southwest that apply directly to the development of this type of model by late 2007.

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments: We agree that the applicable entities for this standard be modified to include the various "Owner" entities as described in the NERC Functional Model Version 3.

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: N/A
   Comments: Not aware of any Regional Variance requirements

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: N/A
   Comments: Not aware of any Business Practice needs

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: N/A

Consideration of Comments on 1st Draft of System Protection Coordination SAR (Project 2007-06)

The System Protection Coordination SAR requesters thank all commenters who submitted comments on the first draft of SAR. This SAR was posted for a 30-day public comment period from June 11 through July 10, 2007. The requesters asked stakeholders to provide feedback on the standard through a special SAR Comment Form. There were 17 sets of comments, including comments from 72 different people from more than 48 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The SAR drafting team made two changes to the SAR based on stakeholder comment:

- Added the Transmission Planner as a reliability function that may be assigned requirements in the revised standard
- Added a sentence to clarify that the monitoring requirements in PRC-001 will not be included in the scope of revisions addressed under this project as they are already being addressed under Project 2006-06 — Reliability Coordination.

Based on the comments received, the drafting team is recommending that the Standards Committee authorize moving the SAR forward to the standard drafting stage of the standards development process.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/System_Protection_Project_2007-06.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Anita Lee (G6)	AESO		✓								
2.	Jay Farrington (G2)	Alabama Electric Coop., Inc.				✓	✓	✓				
3.	Ken Goldsmith (G4)	ALT										✓
4.	Robert Rauschenbach (G2)(I)	Ameren			✓			✓				
5.	Thad Kness	American Electric Power (AEP)	✓				✓	✓				
6.	Jason Shaver	American Transmission Co.	✓									
7.	Dave Rudolph (G4)	BEPC										✓
8.	Dean Bender	Bonneville Power Administration (BPA)	✓		✓		✓	✓				
9.	Brent Kingsford (G6)	CAISO		✓								
10.	Alan Gale (G5)	City of Tallahassee	✓		✓		✓	✓				
11.	Glen McCartney (G3)	Constellation Energy			✓		✓	✓				
12.	Michael Gildea (G3)	Constellation Energy			✓		✓	✓				
13.	Nancy C. Denton	Consumers Energy Company			✓	✓						
14.	Tom Seeley (G2)	E. ON-U.S.	✓									
15.	Charlie Fink (G2)	Entergy	✓		✓		✓	✓				
16.	Jammie Lee (G2)	Entergy	✓		✓		✓	✓				
17.	Steve Myers (G6)	ERCOT										✓
18.	Ken Dresner (G7)	FE, Fossil Generation	✓		✓		✓	✓				
19.	Bill Duge (G7)	FE, Nuclear Generation	✓		✓		✓	✓				
20.	Art Buanno (G7)	FE, Tranmission Planning & Protection	✓		✓		✓	✓				
21.	Bob McFeaters (G7)	FE, Tranmission Planning & Protection	✓		✓		✓	✓				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
22.	Doug Hohlbaugh (G7)	FirstEnergy	✓		✓		✓	✓				
23.	Eric Senkowicz	FRCC										✓
24.	Phil Winston (G2)	Georgia Power Company			✓							
25.	Steve Waldrep (G2)	Georgia Power Company			✓							
26.	Hong-Ming Shuh (G2)	Georgia Transmission Corp.	✓		✓							
27.	Neal Jones (G2)	Georgia Transmission Corp.	✓		✓							
28.	David Kiguel (G3)	Hydro One Networks	✓		✓							
29.	Roger Champagne (G3)(I)	HydroQuebec TransEnergie (HQTE)	✓									
30.	Matt Goldberg (G6)	IESO		✓								
31.	Ron Falsetti (G3) (G6) (I)	IESO		✓								
32.	Charles Yeung (G6)	SPP		✓								
33.	Kathleen Goodman (G3)	ISO-New England		✓								
34.	William Shemley (G3)	ISO-New England		✓								
35.	Eric Ruskamp (G4)	LES	✓		✓		✓	✓				
36.	Donald Nelson (G3)	MADPC									✓	
37.	Robert Coish (G4)	Manitoba Hydro EB	✓		✓		✓	✓				
38.	Walter Marusenko	Manitoba Hydro EB	✓		✓		✓	✓				
39.	Tom Mielnik (G4)	MEC										✓
40.	Joe Knight (G4)	Midwest Reliability Organization										✓
41.	Mike Brytowski (G4)	Midwest Reliability Organization										✓
42.	Terry Bilke (G4)	MISO		✓								
43.	William Phillips (G6)	MISO		✓								
44.	Carol Gerou (G4)	MP	✓		✓		✓	✓				
45.	Ernesto Paon (G2)	Municipal Electric Authority of GA	✓		✓		✓					
46.	Michael Shiavone (G3)	National Grid US	✓									
47.	Greg Campoli (G3)	New York ISO		✓								
48.	Jim Castle (G6)	New York ISO		✓								
49.	Ralph Rufrano (G3)	New York Power Authority	✓		✓							
50.	Guy V. Zito (G3)	NPCC										✓
51.	Al Adamson (G3)	NY State Reliability										✓

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
		Council										
52.	Alicia Daugherty (G6)	PJM		✓								
53.	Jerry Blackley (G2)	Progress Energy Carolinas	✓		✓		✓	✓				
54.	C. Robert Moseley (G1)	PSC of South Carolina									✓	
55.	David A. Wright (G1)	PSC of South Carolina									✓	
56.	Elizabeth B. Fleming (G1)	PSC of South Carolina									✓	
57.	G. O'Neal Hamilton (G1)	PSC of South Carolina									✓	
58.	John E. Howard (G1)	PSC of South Carolina									✓	
59.	Mignon L. Clyburn (G1)	PSC of South Carolina									✓	
60.	Phil Riley (G1)	PSC of South Carolina									✓	
61.	Randy Mitchell (G1)	PSC of South Carolina									✓	
62.	Mike Gentry	Salt River Project	✓		✓		✓	✓				
63.	Bridget Coffman (G2)	SC Public Service Authority	✓									
64.	Pat Huntley (G2)	SERC Reliability Corp.										✓
65.	Marion Frick (G2)	South Carolina Electric & Gas Co.			✓		✓	✓				
66.	E. William Riley	Southwest Transmission Coop.	✓									
67.	Tom D. Spence	Southwest Transmission Coop.	✓									
68.	George Pitts (G2)	Tennessee Valley Authority	✓		✓		✓					
69.	Meyer Kao (G2)	Tennessee Valley Authority	✓		✓		✓					
70.	Jim Haigh (G4)	WAPA	✓					✓				
71.	Neal Balu (G4)	WPS			✓		✓	✓				
72.	Pam Oreschnick (G4)	XEL	✓		✓		✓	✓				

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – Public Service Commission of South Carolina (PSC SC)
G2 – SERC EC Protection & Control Subcommittee (SERC EC PCS)
G3 – CP9 Reliability Standards Working Group (CP9 RSWG)
G4 – Midwest Reliability Organization (MRO)
G5 – FRCC
G6 – IRC Standards Review Committee
G7 – FirstEnergy

Index to Questions, Comments, and Responses

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2. Do you agree with the proposed scope of this SAR? 8
3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)? 11
4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area. 14
5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us. 15
6. If you have any other comments on this SAR that you haven't provided above, please provide them here. 17

1. **Do you agree that there is a reliability-related need to improve the requirements in this standard?**

Summary Consideration: Most commenters agreed that there is a reliability-related need for this SAR. There were no changes made in response to these comments.

Question #1			
Commenter	**Yes**	**No**	**Comment**
AEP		☑	There might not be a directly reliability driver for improving this standard, but the standard should be improved to better clarify responsibilities.
Response: The SAR DT agrees with the comment that the standard should be improved to better clarify responsibilities, but the drafting team also believes that clarifying responsibilities is reliability related.			
SWTC	☑		We agree that there is a need to improve the requirements of Standard PRC-001-0 and Standard MOD-011-0 as described in the supplemental document "NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination". It is important to modify ambiguous statements such as "...corrective action needs to be taken..." and "must be done...as soon as possible...". By making the improvements described in the SAR, the standard will provide the applicable entities with more definitive requirements that will allow entities to provide specific responsibilities to internal work groups within the standard utility organization.
Response: The SAR DT thanks you for your support.			
ATC	☑		Standard has much room for improvement.
Response: The SAR DT agrees with the comment.			
PSC SC	☑		
SERC EC PCS	☑		
BPA	☑		
Consumers Energy	☑		
IESO	☑		
SRP	☑		
Manitoba Hydro	☑		
CP9 RSWG	☑		
Ameren	☑		
MRO	☑		

Question #1			
Commenter	**Yes**	**No**	**Comment**
HQTE	☑		
FRCC	☑		
IRC SRC	☑		
FirstEnergy	☑		

2. **Do you agree with the proposed scope of this SAR?**

Summary Consideration: Most commenters agreed with the proposed scope of the SAR. The SAR DT modified the SAR to clarify that it will coordinate with other DTs to ensure that all requirements in PRC-001will be addressed by one and only one drafting team. The monitoring requirements will be transferred to the DT working on Project 2006-06 for Reliability Coordination.

Question #2			
Commenter	**Yes**	**No**	**Comment**
SERC EC PCS		☑	Consideration should be given to splitting this effort among 2 or 3 standards to address the operating, operations planning, and planning horizons. Consideration should also be given to moving the operating training requirements to another standard (if not already covered by an existing standard).
Response: The SDT will coordinate with the Reliability Coordination standard drafting team working on Project 2006-06 to address these issues. The SAR DT believes that the monitoring requirements should be addressed by the Reliability Coordination SDT, however for coordination and understanding, the SAR DT believes the remaining requirements should be in one standard.			
FirstEnergy		☑	Under the section of Detailed Description it is stated: "This project will address the issues identified by the System Protection and Control Task Force for the planning-related requirements in PRC-001 as well as any planning-related concerns identified in FERC Order 693. (The operations-related requirements in PRC-001 are being addressed under Project 2006-06.) A detailed listing of the areas of the existing standard that need improvement is provided in Attachment B titled "NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination" It seems that it would be more effective to pull the PRC-001 standard from the scope of of the 2006-06 project which deals with mulitple standards and allow this SDT to focus on all aspects of the PRC-001. The SPCTF raised concerns with PRC-001 in both the planning and operations time-frame and it does not appear that the 2006-06 project is scoped to address the SPCTF items.
Response: The SAR DT modified the SAR to clarify that it will coordinate with other drafting teams to ensure that all requirements in PRC-001 will be addressed by one and only one drafting team. The monitoring requirements will be transferred to the DT working on project 2006-06 Reliability Coordination)			
FRCC	☑	☑	Incorporating assessments by subject matter experts such as this NERC SPCTF / Planning Committee assessment into the NERC Standards revision SAR project is an efficient way to supplement project SARs and allows for valuable input at the front-end of the standards process.

			Attachments A and C are not included in the SAR and Attachment B is identified as "Supporting Material". It may be clearer to include all applicable documents within the SAR including relevant excerpts from any FERC assessments and requested changes to the standard.
Response: The SAR DT will ensure that all attachments are clearly labeled and all pertinent documents are included in the final posting.			
SWTC	☑		Another important change described in this SAR is the requirement to have an up-to-date accurate model of the transmission system for protection studies. It is extremely important to develop these accurate models to allow enhance the reliability of the bulk-electric system. There are efforts underway in the southwest that apply directly to the development of this type of model by late 2007.
Response: The SAR DT agrees with your observation- please note the SPCTF's proposed changes for modeling are not addressed in this SAR – they are expected to be addressed in a separate SAR to revise MOD-011.			
ATC	☑		Moving R6 regarding SPS monitoring and status notification to more appropriate PRC SPS section makes sense. Have concern about NERC SPCTF recommendation of merging system short-circuit databases for perfoming wide-area fault studies. See additional comments below.
Response: The SAR DT agrees that R6 should be addressed in another standard; however, the SAR DT believes it belongs in a standard that addresses a broader range of monitoring activities. Please see the summary consideration of comments			
PSC SC	☑		
AEP	☑		
BPA	☑		
Consumers Energy	☑		
IESO	☑		
SRP	☑		
Manitoba Hydro	☑		
CP9 RSWG	☑		
Ameren	☑		
MRO	☑		
HQTE	☑		

IRC SRC	☑		

3. **Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?**

Summary Consideration: Based on stakeholder comments, Transmission Planners have been added to the list of applicable entities.

Question #3			
Commenter	**Yes**	**No**	**Comment**
FRCC			This question may be better addressed as the standard is drafted.
Response: The SAR DT is required to identify the proposed applicability. The applicability will be finalized during standard drafting			
CP9 RSWG		☑	recommend that Transmission Planners be added
Response: The SAR DT agrees and Transmission Planners have been added to the applicability list.			
HQTE		☑	recommend that Transmission Planners be added
Response: The SAR DT agrees and Transmission Planners have been added to the applicability list.			
FirstEnergy		☑	FE agrees with the SPCTF that the TO, GO and DP should be added to the applicability section of this standard as many of the requirements will originate from these entities. However, it may be necessary to add the Transmission Planner (TP) entity for "planning" related requirements. For example, the existing R3 requires coordination of new or revised protections systems. It may be short-sighted to assume that the TO is the entity who would coordinate this work; there may be situations where a Transmission Planner performs this work and is best suited to share the information with neighboring system owners/planners as well as the Planning Coordinator.
Response: The SAR DT agrees and Transmission Planners have been added to the applicability list.			
IESO	☑	☑	It is not clear based on the information presented how all the functional entities are involved. As an example, no reference is noted in the documents for PC responsibility. Is it inferred that if a coordination model is developed on a wide area basis, the PC will be the responsible entity? Functional Model entity definitions, tasks, and obligations must be followed while developing applicability of the requirements.
Response: the SAR DT checked all the functional entities that are currently assigned responsibility for requirements in PRC-001 and also checked those functional entities that are expected to be assigned requirements based on the SPTCF analysis of PRC-001. Please see the SPTCF report posted as a supporting document on the website.			

Please note the SPCTF's proposed changes for modeling are not addressed in this SAR – they are expected to be addressed in another SAR for modifications to MOD-011. As envisioned, a new requirement may need to be developed to support the orignial R1 which says: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. Although the original R1 is not written in a format that is easy to measure, the SAR DT believes the intent of R1 is to ensure that real-time operating personnel have information about protection schemes so they will know what actions to take when the protection schemes are not in service. The SAR DT believes the Planning Coordinator may be the best functional entity to provide this data to the real-time operating personnel. As envisioned, this discussion will take place with stakeholders during standard drafting. The standards process requires that DTs consider the Functional Model elements when developing standards.			
IRC SRC	☑	☑	It is not clear based on the information presented if all the functional entities involved are identified in the scope of the standard. As an example, no reference is noted in the documents for TP responsibility. It is inferred that if a coordination model is developed on a wide area basis, the PC will be the only responsible entity. However there may be requirements for the TP as well.
Response: The SAR DT agrees and Transmission Planners have been added to the applicability list.			
SERC EC PCS	☑		The requirements for the PC, TO, GO, and DP (planning horizon) should be in a separate standard than those for the RC, BA, TOP, and GOP (operating and operations planning horizons).
Response: While the SAR DT agrees that some requirements for entities providing real time operations should be transferred to other standards, for coordination and understanding the SAR DT believes the remaining requirements should be in one standard.			
SWTC	☑		We agree that the applicable entities for this standard be modified to include the various "Owner" entities as described in the NERC Functional Model Version 3.
Response: The SAR DT agrees - thank you for your comments.			
PSC SC	☑		
AEP	☑		
BPA	☑		
Consumers Energy	☑		
SRP	☑		
ATC	☑		

Manitoba Hydro	☑		
Ameren	☑		
MRO	☑		

4. **If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.**

Summary Consideration: The stakeholders who submitted comments did not identify any regional variances.

Question #4		
Commenter	**Regional Variance**	**Comment**
PSC SC	N/A	
SERC EC PCS	None.	
AEP	None.	None.
BPA		No known variance.
Consumers Energy	N/A	
SWTC	N/A	Not aware of any Regional Variance requirements.
ATC	N/A	
Manitoba Hydro	None	No variance necessary.
CP9 RSWG	N/A	No Regional Variance
Ameren	None	
MRO	None	
HQTE		No Regional Variance
FRCC	N/A	
FirstEnergy		Aware of none

5. **If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.**

Summary Consideration: The stakeholders who submitted comments did not identify any specific business practice that need to be developed to support the modifications to PRC-001 proposed with this SAR.

Question #5		
Commenter	**Business Practice**	**Comment**
AEP	Possibly	AEP and other utilities, with many years of experience serving customers and supporting the electric grid, have voluntarily integrated protection coordination processes into the core of their work practices . AEP fully supports improvements if they truly foster reliability and availability benefits to bulk power transfers. More Standards, Requirements, and Business Practices are not always better. If Standards create burdens on a utility's physical resources and budgets, then some mechanism must be available to allow for the needed changes.
Response: Please monitor the work of the SDT and advise us if added burdens are created and advise us of the need for any business practice or other mechanism necessary.		
ATC	Data entry and maintenance procedures for proposed wide-area short circuit model would need to be developed.	Creating and maintaining the proposed wide-area short-circuit database, although useful, might prove quite difficult to implement. Among our concerns: Impedance units- Ohms or per unit? If per unit, using what common base? CAPE to ASPEN & ASPEN to CAPE conversion issues? Need for unique and consistent bus numbers for all busses in combined database. If using CAPE, coordination and application of database categories. Who would be responsible for merging the databases and then maintaining the common database? How often would the databases be remerged to reflect system changes?
Response: Please note the SPCTF's proposed changes for modeling are not addressed in this SAR – they are expected to be addressed in a SAR proposing changes to MOD-011.		
PSC SC		N/A
SERC EC PCS	None.	
Consumers Energy	N/A	
SWTC	N/A	Not aware of any Business Practice needs.
Manitoba Hydro	None	No comments
CP9 RSWG		No Business Practice

Question #5		
Commenter	**Business Practice**	**Comment**
Ameren	No	
MRO	None	
HQTE		No Business Practice
FirstEnergy		Aware of none

6. **If you have any other comments on this SAR that you haven't provided above, please provide them here.**

Summary Consideration: The SAR DT did not make any changes to the SAR based on modifications proposed by stakeholders in response to this question.

Question #6	
Commenter	**Comment**
AEP	For clarifying protective systems, the standard should not use the term Bulk Electric System, but should instead specify a voltage threshold for impacts to bulk system transfers - specifically; 'Facilites operated 200 kV and above and Regionally-defined, Operationally Significant facilities operated greater than 100 kv, but less than 199 kV'. The term 'affects' also needs to be clarified. Inclusion of all facilities greater than 100 kV does not benefit the reliability of national bulk power transfers. For example, the loss or misoperation of a 138 kV line serving a localized load center would not be detremental to bulk power transfers multiple busses away.
Response: The comment will be referred to the SDT when convened for consideration when drafting the standard.	
FRCC	The Drafting team should coordinate any system protection terminology introduced or re-defined within this standard with other system protection related SARs (i.e. Disturbance monitoring, System Protection Maintenance and Testing) to ensure common terminology is appropriately defined in the standards glossary.
Response: This coordination is required by the standards process. The comment will be referred to the SDT when convened for consideration when drafting the standard.	
SRP	I am concerned with the language proposed by FERC and the comparison to reactions to IROL's. Will FERC's requirement apply to a single protection system that has a redundant protection system? Will FERC's requirement apply to a system that is in an "overexposed" state? Will FERC's requirement apply to a system that may be exposed to slow 30 cycle of less tripping. These conditions must be identified in detail as to what will need to meet the "returning the system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes." FERC requirement
Response: The comment will be referred to the SDT when convened for consideration when drafting the standard.	
ATC	Background Information Section on this comment sheet should read: Please e-mail your comments on this form to sarcomm@nerc.net with subject "Protection Coordination SAR" in subject line, not "Protection Maintenance SAR" as stated.
Response: Thank you for your comment	
Ameren	Development of inter-company short circuit modeling should be cover in a separate MOD standard. Maintaining one large overall regional short circuit model is neither practical nor necessary. Standard methods to exchange short circuit data of tie-line plus one breakered bus into the neighboring systems should be adequate and be developed. Otherwise Ameren agrees with SPCTF recommendations.
Response: Please note the SPCTF's proposed changes for modeling are not addressed in this SAR – they are expected to be addressed in a SAR proposing changes to MOD-011.	
MRO	The MRO commends NERC and the SDT for taking the necessary steps to remove the vagueness and ambiguity

	in the requirements; as well as the need to have clarity and measurability now that the industry has transitioned to mandatory and enforceable standards. The SPCTF Assessment of PRC-001-1 did not mention how they would address "Corrective Actions" listed in R2. The MRO requests that the SDT expand on what the scope of these "Corrective Actions" is meant to be (e.g. real-time, or after the fact repair or replacement of defective equipment).
Response: These issues are discussed in FERC Order 693 and will be considered by the SDT	
IESO	The IESO commends NERC, the SDT and the SPCTF (White Paper) for providing clarifications and improvements in the system protection areas.
Response: Thank you	
IRC SRC	The SRC commends NERC, the SDT and the SPCTF for providing this clarification and improvements in the system protection areas.
Response: Thank you	
PSC SC	N/A
SERC EC PCS	None.
Consumers Energy	None.
SWTC	N/A
Manitoba Hydro	No comments
CP9 RSWG	None
HQTE	None
FirstEnergy	none

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard	**PRC-001-1 — System Protection Coordination (Project 2007-06)**
Request Date	May 7, 2007
Revised Date	July 27, 2007

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)
Name NERC System Protection and Control Task Force (Attachment A)	☐	New Standard
Primary Contact Charles Rogers (SPCTF Chairman)	☒	Revision to existing Standard
Telephone 517-788-0027 Fax 517-788-0917	☐	Withdrawal of existing Standard
E-mail cwrogers@cmsenergy.com	☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

The purpose of standard PRC-001-1 — System Protection Coordination should remain "To ensure system protection is coordinated among operating entities." The standard should be revised to:

1. Assure that Protection System application and performance issues are coordinated among all related entities.
2. Correct the applicable entities within the standard to reflect the actual functional responsibilities, as described in the NERC Functional Model.
3. Incorporate other general improvements described in the standards development work plan and from other sources.
4. Address directives received from ERO regulatory authorities.
5. Consider the observations and recommendations developed by the NERC SPCTF, which are detailed in the attached report (Attachment B), approved by the Planning Committee in December 2006.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

Protection system coordination is an absolute necessity for the North American electric system to operate properly. PRC-001 is a Version 0 standard, and was translated from an operating policy that was appropriate in an era of voluntary compliance.

The Version 0 standards and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update those standards, incorporating improvements to make the standards more suitable for enforcement.

Both FERC (within Order 693) and the SPCTF (in their report on PRC-001) identified significant shortcomings in the existing standard.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

The existing PRC-001 Standard has been identified in the Reliability Standards Development Plan as requiring revision, within the FERC Order 693 as requiring revisions, and by a SPCTF report (attached) which identified a number of issues with the existing standard (the SPCTF report, which precedes FERC Order 693, also includes observations from the preceding FERC NOPR on RM-06-16-000). This revision of PRC-001 should address concerns from these sources and should include the upgrades to the standard identified in Attachment C to bring the revised standard into conformance with the latest version of the ERO Rules of Procedure.

The PRC 001 standards drafting team will coordinate the transfer of monitoring related requirements to appropriate other standards through coordination with the standards drafting teams associated with project 2006-06 (Reliability Coordination)

Detailed Description

This project will address the issues identified by the System Protection and Control Task Force for the planning-related requirements in PRC-001 as well as any planning-related concerns identified in FERC Order 693. (The operations-related requirements in PRC-001 are being addressed under Project 2006-06.) A detailed listing of the areas of the existing standard that need improvement is provided in Attachment B titled “NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination”

The drafting team will also make the improvements to the standard identified in Attachment C – “Reliability Standards Review Guidelines” to bring the revised standard into conformance with the latest version of the ERO Rules of Procedure.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator Area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☒	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
MOD-011-0	Modify to include the essential data for wide-area fault studies, as noted in the attached SPCTF report on PRC-001.

Related SARs

SAR ID	Explanation
RC SAR	Project 2006-06 – Reliability Coordination includes modification of the real-time requirements but does not address the planning-related requirements.

Regional Variances

Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
SERC	None
RFC	None
SPP	None
WECC	None

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Chairman / RFC-ECAR Representative
Principal Engineer
Consumers Energy Co.

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System Protection Manager
TXU Electric Delivery

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NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination

December 7, 2006

A Technical Review of Standards

Prepared by the
System Protection and Controls Task Force
of the
NERC Planning Committee

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Appendix B — SYSTEM PROTECTION AND CONTROL TASK FORCE 9

This report was approved by the Planning Committee on December 7, 2006, for forwarding to the Standards Committee.

Introduction

When the original scope for the System Protection and Control Task Force was developed, one of the assigned items was to review all of the existing PRC-series Reliability Standards, to advise the Planning Committee of our assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.

This report presents the SPCTF's assessment of PRC-001-0 – System Protection Coordination. The report includes the SPCTF's understanding of the intent of this standard and contains specific observations relative to the existing standard.

This standard was developed by translating the requirements of an earlier Phase I Planning Standard; thus it has not been previously subjected to a critical review of the Requirements.

Executive Summary

This reliability standard is intended to assure that system protection is coordinated between multiple transmission entities and between generation entities and transmission entities. It appears that this standard is intended to address coordination of protection functions and capabilities in both the operating time frame and the planning time frame. These time frames, as they apply to protective functions, are discussed, as are the various responsibilities to assure the related coordination.

The SPCTF concludes that the list of applicable entities in the existing standard is incomplete and that the assigned responsibilities do not reflect the activities of the identified functions. Significantly, the existing standard disregards the significant responsibilities and roles of the equipment owners; specifically, the Transmission Owners and Generator Owners.

The SPCTF also concludes that the Requirements of the existing standard are vague and ambiguous, and that, while Measures and Levels of Non-Compliance are defined, these are essentially unenforceable because of fundamental flaws within the requirements.

Assessment of PRC-001-0

General Comments

The SPCTF offers the following general comments:

1. None of the requirements within PRC-001-0 specifically indicate what protective systems are being addressed.
2. The phrase "protective relay or equipment" is a recurring phrase, and generally should be revised to "protective system" or "protective system equipment."
3. The phrase "If a protective relay or equipment failure reduces system reliability" is ambiguous, and needs additional clarification. This phrase does not clearly state when failures must be reported.
4. Many of the requirements list the Balancing Authority as an applicable entity. It does not seem that the Balancing Authority has the direct responsibility for any of these activities, and only needs to respond to the various issues when directed by the Transmission Operator and/or Generator Operator.

Applicability

4.1. Balancing Authorities
4.2. Transmission Operators

4.3. Generator Operators

The remainder of the PRC-series standards rarely assigns any responsibility for protection systems to any of the above entities. Specifically, the responsibilities for disturbance monitoring (which includes some monitoring of protective systems) and for protective system maintenance apply to the equipment owners, specifically Transmission Owners and Generator Owners. The current applicable entities do, however, have a role in the functions of this standard. The SPCTF asserts that Transmission Owner, Generator Owner, and Distribution Provider should be added to the list of Applicable Entities.

R1

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protective system schemes applied it its area.

This requirement is a statement of a highly laudable goal, but this is not specific and enforceable. In fact, the drafting team that was providing missing Measures and Compliance Elements was unable to assign either to this requirement.

It may be possible to restate this requirement in such a way to be measurable and enforceable. The protective system equipment owners (Transmission Owners, Generator Owners, and Distribution Providers) should be responsible to provide the necessary information to the Transmission Operator and Generator Operator to facilitate their familiarity with the relevant protective systems.

R2

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

Requirement R2 addresses the operating horizon, but the equipment owner entities will be familiar with the condition of their protective system equipment.

Therefore, the responsibility for this requirement must originate with the owner entities: the Transmission Owner, Generator Owner, and Distribution Provider. These entities should inform the Transmission Operator, Generator Operator, and Balancing Authorities of equipment failures pertinent to this requirement. The Transmission Operators may need to have to coordinate with each other, similar to the existing requirement R4.

The requirement for corrective action, “as soon as possible”, is vague and ambiguous, and needs modification to be specific.

As evidenced by the lack of a related Measure (via the drafting team for missing Measures and Compliance Elements), this requirement is currently not measurable.

R3

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

> **R3.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
>
> **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

Not only new protective systems and changes to protective systems should be coordinated. A requirement should be added to require coordination of all existing protective systems. Then, requirement R3 should require the coordination new protective systems and changes to protective systems with existing protective systems.

Requirement R3 addresses the planning horizon; therefore, this responsibility should be assigned to the Transmission Owner, Generator Owner, and Distribution Provider.

In addition, R3.1 should be bi-directional; the Transmission entity should provide similar coordination with the Generator entity.

R4

R4. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

It's unclear whether this requirement addresses the operations planning horizon or the planning horizon.

If Requirement R4 addresses the planning horizon, the responsibilities should be assigned similarly to the recommendations for R3, to the Transmission Owner, Generator Owner, and Distribution Provider. If Requirement R4 addresses the planning horizon, it seems to be redundant with R3 to some extent.

R5

> **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:
>
> **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.
>
> **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.

Requirement R5 addresses the both the planning horizon and operating planning horizon. It is essential to the reliability of the system that this activity occurs, and it must occur in advance of any changes to the system.

In the operations planning horizon, the Operator entities should coordinate these changes with the Owner entities, since the Owners have the tools to analyze the effects of these system changes on the protective systems and the access to the protective systems to make any needed changes to the protective system.

In the planning horizon, the owner entities should be responsible for this requirement, similarly to Requirement R3.

R6

> **R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

Requirement R6 addresses the operating horizon. The Owners have to monitor the status of Special Protection Systems and provide the status to the Operators. The Operators then should coordinate the availability of Special Protection Systems between each other, and take any necessary operating actions to address issues with Special Protection Systems.

This requirement needs to better define "status of … Special Protection System…"

This requirement may be better moved to one of the PRC-series standards specifically addressing Special Protection Systems.

Related Standard
MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures

Also, while reviewing PRC-001, the SPCTF noted that no existing NERC Standard requires that a consistent model be maintained for protection studies, such as that required by MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures, for other steady-state studies. Without such a model, various Transmission Owners, Generator Owners, and Distribution Providers cannot accurately

apply the protective relaying. To address this deficiency, the SPCTF recommends that MOD-011, Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures, be modified to include the essential data for wide-area fault studies. The specific MOD-011 requirements are listed below, together with suggested modifications.

R1.2 – Generators
Recommend including direct-axis synchronous reactance (X_d), transient reactance (X_d'), sub transient reactance (X_d"), and the associated time constants (T_{do}, T_{do}', and T_{do}") for synchronous generators. For induction and inverter generators, generically include the data necessary to model the equipment in short circuit models in the positive, negative, and zero sequence domains.

R1.3 – Transmission Lines
Recommend specifying the positive and zero sequence impedance, including mutual impedances

R1.5 – Transformers
Recommend specifying positive sequence and zero sequence impedance, including all grounding effects.

FERC Assessment of PRC-001-0

In the October 20, 2006, the Notice of Proposed Rulemaking for adoption of NERC Standards (Docket Number RM06-16-000), the Federal Energy Regulatory Commission, for the most part, considered the operating horizon impacts of PRC-001. FERC proposed that PRC-001-0 be approved as mandatory and enforceable. They did, however, propose that NERC be directed to make modifications to PRC-001. The modifications proposed in the NOPR are excerpted from the NOPR and repeated below:

> "The Commission proposes to direct that NERC submit a modification to PRC-001-0 that: (1) includes Measures and Levels of Non-Compliance; (2) includes a requirement that relevant transmission operators and generator operators must be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities can carry out the appropriate corrective control actions consistent with those used in mitigating IROL violations; and (3) clarifies that, after being informed of failures in relays or protection system elements on the Bulk-Power System, transmission operators or generator operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes."

Other Activities related to PRC-001-0

The Standard Drafting Team on Missing Measures and Compliance Elements modified PRC-001-0 as a part of their work, but the requirements were not changed. As this report is being prepared, the modified Standard is being balloted.

A draft SAR for the revision of PRC-001-0 is included in the "Draft Reliability Standards Development Plan: 2007–2009", which was presented to the NERC Board of Trustees for their approval on November 1, 2006. This draft SAR is entitled, "System Protection Project (2009-01)", and discusses many of the same deficiencies in PRC-001-1 that were identified by the SPCTF.

Conclusion and Recommendation

As it exists today, enforcement of PRC-001-0 will be very difficult. The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the "operating horizon," "operations planning horizon," and "planning horizon" protection coordination issues, the deficiencies in the current standard are magnified.

The SPCTF recommends that the existing draft Standards Authorization Request that is included in the "Draft Reliability Standards Development Plan: 2007–2009" be modified to include the observations from the SPCTF assessment of PRC-001-0 and also include the modifications directed in the FERC NOPR on RM06-16-000. The SPCTF also recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards.

In addition, it is not possible to effectively coordinate protective systems without having accurate short circuit models of neighboring systems. To address these modeling issues related to data for short circuit calculations, the SPCTF recommends that a Standards Authorization Request be developed to modify Standard MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures, to address these issues. Data for short circuit calculations, as noted in this report, should be considered as additional requirements within MOD-013-1.

Appendices

Appendix A is not relevant to this SAR and was removed

Appendix B — SYSTEM PROTECTION AND CONTROL TASK FORCE

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Bob Stuart
NERC Blackout Investigation Team
Director of Business Development, Principal T&D Consultant
Elequant, Inc.

Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;
or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative

conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature; or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon
The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels
The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replace existing 'levels of non-compliance.') The violation severity levels must be applied for each requirement and may be combined to cover multiple requirements, as long as it is clear which requirements are included and that all requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: more than 95% but less than 100% compliant.
- **Moderate: mostly compliant with significant exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: more than 85% but less than or equal to 95% compliant.
- **High: marginal performance or results** — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more

significant elements. Equivalent score: more than 70% but less than or equal to 85% compliant.

- **Severe: poor performance or results** — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: 70% or less compliant.

Compliance Monitor
Replace, ‘Regional Reliability Organization’ with ‘Regional Entity’

Fill-in-the-blank Requirements
Do not include any ‘fill-in-the-blank’ requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan. The effective date should be linked to the NERC BOT adoption date.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, ‘Associated Documents’.

Functional Model Version 3
Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Standard Authorization Request Form

Title of Proposed Standard	**PRC-001-1 — System Protection Coordination (Project 2007-06)**
Request Date	May 7, 2007
Revised Date	July 27, 2007

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)
Name NERC System Protection and Control Task Force (Attachment A)	☐	New Standard
Primary Contact Charles Rogers (SPCTF Chairman)	☒	Revision to existing Standard
Telephone 517-788-0027 Fax 517-788-0917	☐	Withdrawal of existing Standard
E-mail cwrogers@cmsenergy.com	☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

The purpose of standard PRC-001-1 — System Protection Coordination should remain "To ensure system protection is coordinated among operating entities." The standard should be revised to:

1. Assure that Protection System application and performance issues are coordinated among all related entities.
2. Correct the applicable entities within the standard to reflect the actual functional responsibilities, as described in the NERC Functional Model.
3. Incorporate other general improvements described in the standards development work plan and from other sources.
4. Address directives received from ERO regulatory authorities.
5. Consider the observations and recommendations developed by the NERC SPCTF, which are detailed in the attached report (Attachment B), approved by the Planning Committee in December 2006.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

Protection system coordination is an absolute necessity for the North American electric system to operate properly. PRC-001 is a Version 0 standard, and was translated from an operating policy that was appropriate in an era of voluntary compliance.

The Version 0 standards and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update those standards, incorporating improvements to make the standards more suitable for enforcement.

Both FERC (within Order 693) and the SPCTF (in their report on PRC-001) identified significant shortcomings in the existing standard.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

The existing PRC-001 Standard has been identified in the Reliability Standards Development Plan as requiring revision, within the FERC Order 693 as requiring revisions, and by a SPCTF report (attached) which identified a number of issues with the existing standard (the SPCTF report, which precedes FERC Order 693, also includes observations from the preceding FERC NOPR on RM-06-16-000). This revision of PRC-001 should address concerns from these sources and should include the upgrades to the standard identified in Attachment C to bring the revised standard into conformance with the latest version of the ERO Rules of Procedure.

The PRC 001 standards drafting team will coordinate the transfer of monitoring related requirements to appropriate other standards through coordination with the standards drafting teams associated with project 2006-06 (Reliability Coordination)

Detailed Description

This project will address the issues identified by the System Protection and Control Task Force for the planning-related requirements in PRC-001 as well as any planning-related concerns identified in FERC Order 693. (The operations-related requirements in PRC-001 are being addressed under Project 2006-06.) A detailed listing of the areas of the existing standard that need improvement is provided in Attachment B titled “NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination”

The drafting team will also make the improvements to the standard identified in Attachment C – “Reliability Standards Review Guidelines” to bring the revised standard into conformance with the latest version of the ERO Rules of Procedure.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator Area.
☒ ~~☐~~	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☒	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage. Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes

5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
MOD-011-0	Modify to include the essential data for wide-area fault studies, as noted in the attached SPCTF report on PRC-001.

Related SARs

SAR ID	Explanation
RC SAR	Project 2006-06 – Reliability Coordination includes modification of the real-time requirements but does not address the planning-related requirements.

Regional Variances

Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
SERC	None
RFC	None
SPP	None
WECC	None

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Principal Engineer
Consumers Energy Co.

W. Mark Carpenter
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NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination

December 7, 2006

A Technical Review of Standards

Prepared by the
System Protection and Controls Task Force
of the
NERC Planning Committee

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This report was approved by the Planning Committee on December 7, 2006, for forwarding to the Standards Committee.

Introduction

When the original scope for the System Protection and Control Task Force was developed, one of the assigned items was to review all of the existing PRC-series Reliability Standards, to advise the Planning Committee of our assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.

This report presents the SPCTF's assessment of PRC-001-0 – System Protection Coordination. The report includes the SPCTF's understanding of the intent of this standard and contains specific observations relative to the existing standard.

This standard was developed by translating the requirements of an earlier Phase I Planning Standard; thus it has not been previously subjected to a critical review of the Requirements.

Executive Summary

This reliability standard is intended to assure that system protection is coordinated between multiple transmission entities and between generation entities and transmission entities. It appears that this standard is intended to address coordination of protection functions and capabilities in both the operating time frame and the planning time frame. These time frames, as they apply to protective functions, are discussed, as are the various responsibilities to assure the related coordination.

The SPCTF concludes that the list of applicable entities in the existing standard is incomplete and that the assigned responsibilities do not reflect the activities of the identified functions. Significantly, the existing standard disregards the significant responsibilities and roles of the equipment owners; specifically, the Transmission Owners and Generator Owners.

The SPCTF also concludes that the Requirements of the existing standard are vague and ambiguous, and that, while Measures and Levels of Non-Compliance are defined, these are essentially unenforceable because of fundamental flaws within the requirements.

Assessment of PRC-001-0

General Comments

The SPCTF offers the following general comments:

1. None of the requirements within PRC-001-0 specifically indicate what protective systems are being addressed.
2. The phrase "protective relay or equipment" is a recurring phrase, and generally should be revised to "protective system" or "protective system equipment."
3. The phrase "If a protective relay or equipment failure reduces system reliability" is ambiguous, and needs additional clarification. This phrase does not clearly state when failures must be reported.
4. Many of the requirements list the Balancing Authority as an applicable entity. It does not seem that the Balancing Authority has the direct responsibility for any of these activities, and only needs to respond to the various issues when directed by the Transmission Operator and/or Generator Operator.

Applicability

4.1. Balancing Authorities
4.2. Transmission Operators

4.3. Generator Operators

The remainder of the PRC-series standards rarely assigns any responsibility for protection systems to any of the above entities. Specifically, the responsibilities for disturbance monitoring (which includes some monitoring of protective systems) and for protective system maintenance apply to the equipment owners, specifically Transmission Owners and Generator Owners. The current applicable entities do, however, have a role in the functions of this standard. The SPCTF asserts that Transmission Owner, Generator Owner, and Distribution Provider should be added to the list of Applicable Entities.

R1

> **R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protective system schemes applied it its area.

This requirement is a statement of a highly laudable goal, but this is not specific and enforceable. In fact, the drafting team that was providing missing Measures and Compliance Elements was unable to assign either to this requirement.

It may be possible to restate this requirement in such a way to be measurable and enforceable. The protective system equipment owners (Transmission Owners, Generator Owners, and Distribution Providers) should be responsible to provide the necessary information to the Transmission Operator and Generator Operator to facilitate their familiarity with the relevant protective systems.

R2

> **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
>
> **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
>
> **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

Requirement R2 addresses the operating horizon, but the equipment owner entities will be familiar with the condition of their protective system equipment.

Therefore, the responsibility for this requirement must originate with the owner entities: the Transmission Owner, Generator Owner, and Distribution Provider. These entities should inform the Transmission Operator, Generator Operator, and Balancing Authorities of equipment failures pertinent to this requirement. The Transmission Operators may need to have to coordinate with each other, similar to the existing requirement R4.

The requirement for corrective action, “as soon as possible”, is vague and ambiguous, and needs modification to be specific.

As evidenced by the lack of a related Measure (via the drafting team for missing Measures and Compliance Elements), this requirement is currently not measurable.

R3

> **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
>
> **R3.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
>
> **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

Not only new protective systems and changes to protective systems should be coordinated. A requirement should be added to require coordination of all existing protective systems. Then, requirement R3 should require the coordination new protective systems and changes to protective systems with existing protective systems.

Requirement R3 addresses the planning horizon; therefore, this responsibility should be assigned to the Transmission Owner, Generator Owner, and Distribution Provider.

In addition, R3.1 should be bi-directional; the Transmission entity should provide similar coordination with the Generator entity.

R4

> **R4.** Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

It's unclear whether this requirement addresses the operations planning horizon or the planning horizon.

If Requirement R4 addresses the planning horizon, the responsibilities should be assigned similarly to the recommendations for R3, to the Transmission Owner, Generator Owner, and Distribution Provider. If Requirement R4 addresses the planning horizon, it seems to be redundant with R3 to some extent.

R5

R5.	A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems. **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.

Requirement R5 addresses the both the planning horizon and operating planning horizon. It is essential to the reliability of the system that this activity occurs, and it must occur in advance of any changes to the system.

In the operations planning horizon, the Operator entities should coordinate these changes with the Owner entities, since the Owners have the tools to analyze the effects of these system changes on the protective systems and the access to the protective systems to make any needed changes to the protective system.

In the planning horizon, the owner entities should be responsible for this requirement, similarly to Requirement R3.

R6

R6.	Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

Requirement R6 addresses the operating horizon. The Owners have to monitor the status of Special Protection Systems and provide the status to the Operators. The Operators then should coordinate the availability of Special Protection Systems between each other, and take any necessary operating actions to address issues with Special Protection Systems.

This requirement needs to better define "status of … Special Protection System…"

This requirement may be better moved to one of the PRC-series standards specifically addressing Special Protection Systems.

Related Standard
MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures

Also, while reviewing PRC-001, the SPCTF noted that no existing NERC Standard requires that a consistent model be maintained for protection studies, such as that required by MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures, for other steady-state studies. Without such a model, various Transmission Owners, Generator Owners, and Distribution Providers cannot accurately

apply the protective relaying. To address this deficiency, the SPCTF recommends that MOD-011, Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures, be modified to include the essential data for wide-area fault studies. The specific MOD-011 requirements are listed below, together with suggested modifications.

> **R1.2 – Generators**
> Recommend including direct-axis synchronous reactance (X_d), transient reactance (X_d'), sub transient reactance (X_d"), and the associated time constants (T_{do}, T_{do}', and T_{do}") for synchronous generators. For induction and inverter generators, generically include the data necessary to model the equipment in short circuit models in the positive, negative, and zero sequence domains.
>
> **R1.3 – Transmission Lines**
> Recommend specifying the positive and zero sequence impedance, including mutual impedances
>
> **R1.5 – Transformers**
> Recommend specifying positive sequence and zero sequence impedance, including all grounding effects.

FERC Assessment of PRC-001-0

In the October 20, 2006, the Notice of Proposed Rulemaking for adoption of NERC Standards (Docket Number RM06-16-000), the Federal Energy Regulatory Commission, for the most part, considered the operating horizon impacts of PRC-001. FERC proposed that PRC-001-0 be approved as mandatory and enforceable. They did, however, propose that NERC be directed to make modifications to PRC-001. The modifications proposed in the NOPR are excerpted from the NOPR and repeated below:

> "The Commission proposes to direct that NERC submit a modification to PRC-001-0 that: (1) includes Measures and Levels of Non-Compliance; (2) includes a requirement that relevant transmission operators and generator operators must be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities can carry out the appropriate corrective control actions consistent with those used in mitigating IROL violations; and (3) clarifies that, after being informed of failures in relays or protection system elements on the Bulk-Power System, transmission operators or generator operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes."

Other Activities related to PRC-001-0

The Standard Drafting Team on Missing Measures and Compliance Elements modified PRC-001-0 as a part of their work, but the requirements were not changed. As this report is being prepared, the modified Standard is being balloted.

A draft SAR for the revision of PRC-001-0 is included in the "Draft Reliability Standards Development Plan: 2007–2009", which was presented to the NERC Board of Trustees for their approval on November 1, 2006. This draft SAR is entitled, "System Protection Project (2009-01)", and discusses many of the same deficiencies in PRC-001-1 that were identified by the SPCTF.

Conclusion and Recommendation

As it exists today, enforcement of PRC-001-0 will be very difficult. The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the "operating horizon," "operations planning horizon," and "planning horizon" protection coordination issues, the deficiencies in the current standard are magnified.

The SPCTF recommends that the existing draft Standards Authorization Request that is included in the "Draft Reliability Standards Development Plan: 2007–2009" be modified to include the observations from the SPCTF assessment of PRC-001-0 and also include the modifications directed in the FERC NOPR on RM06-16-000. The SPCTF also recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards.

In addition, it is not possible to effectively coordinate protective systems without having accurate short circuit models of neighboring systems. To address these modeling issues related to data for short circuit calculations, the SPCTF recommends that a Standards Authorization Request be developed to modify Standard MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures, to address these issues. Data for short circuit calculations, as noted in this report, should be considered as additional requirements within MOD-013-1.

Appendices

Appendix A is not relevant to this SAR and was removed

Appendix B — SYSTEM PROTECTION AND CONTROL TASK FORCE

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NERC Blackout Investigation Team
Director of Business Development, Principal T&D Consultant
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Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replace existing 'levels of non-compliance.') The violation severity levels must be applied for each requirement and may be combined to cover multiple requirements, as long as it is clear which requirements are included and that all requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: more than 95% but less than 100% compliant.
- **Moderate: mostly compliant with significant exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: more than 85% but less than or equal to 95% compliant.

- **High: marginal performance or results** — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: more than 70% but less than or equal to 85% compliant.
- **Severe: poor performance or results** — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: 70% or less compliant.

Compliance Monitor
Replace, 'Regional Reliability Organization' with 'Regional Entity'

Fill-in-the-blank Requirements
Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan. The effective date should be linked to the NERC BOT adoption date.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Functional Model Version 3
Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

August 15, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Nomination Periods Open for Three Drafting Teams

The Standards Committee announces the following standards actions:

Nominations for Project 2006-01 System Personnel Training Standard Drafting Team (August 15–29, 2007)

The Standards Committee is seeking additional industry experts to serve on the System Personnel Training Standard Drafting Team. The new members will join the already-formed drafting team in developing the following standard:

- PER-005 — System Personnel Training

If you are interested in serving on this standard drafting team, please complete this nomination form and return it to sarcomm@nerc.net by August 29, 2007 with "System Personnel Training SDT" in the subject line. For questions, please contact Linda Clarke at 610-310-7210 or linclrke@msn.com.

Nominations for Project 2007-06 System Protection Coordination Standard Drafting Team (August 15–29, 2007)

The Standards Committee is seeking industry experts to serve on the System Protection Coordination Standard Drafting Team. The drafting team will work on modifications to the following standard:

- PRC-001 — System Protection Coordination

If you are interested in serving on this standard drafting team, please complete this nomination form and return it to sarcomm@nerc.net by August 29, 2007 with "System Protection Coordination SDT" in the subject line. For questions, please contact Al Calafiore at 678-524-1188 or at al.calafiore@nerc.net.

Nominations for Project 2007-17 Protection System Maintenance and Testing Standard Drafting Team (August 15–29, 2007)

The Standards Committee is seeking industry experts to serve on the Protection System Maintenance and Testing Standard Drafting Team. If you are interested in serving on this team, please complete this nomination form and return it to sarcomm@nerc.net with "Protection System Maintenance SDT" in the subject line by August 29, 2007. For questions, please contact Al Calafiore at 678-524-1188 or at al.calafiore@nerc.net.

The drafting team will work on revising the following standards:

- PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs
- PRC-011-0 — UVLS System Maintenance and Testing
- PRC-017-0 — Special Protection System Maintenance and Testing

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Draft 1 of SAR posted for comment June 11, 2007 – July 10, 2007.
2. SAR approved on August 13, 2007.
3. First posting of revised standard PRC-001-2 on September 11, 2009.
4. Transitioned from a revision of PRC-001-1 to development of PRC-027-1 based on industry comments, Quality Review feedback, and consideration of FERC directives relative to the existing requirements of PRC-001-1.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPC SDT) created a new results-based standard, PRC-027-1, to coordinate Protection Systems utilized to protect Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards. This standard incorporates and enhances the coordination aspects of Requirements R3 and R4 from PRC-001-1 (now R2 and R3 of PRC-001-2). The SPC SDT is requesting a posting for stakeholder comments under a 30-day formal comment period.

Anticipated Actions	Anticipated Date
Post first draft of standard for 30-day Formal Comment Period.	May 2012
45-day Formal Comment Period with Parallel Initial Ballot	August 2012
30-day Formal Comment Period with Parallel Successive Ballot	November 2012

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is three months beyond the date that this standard is approved by applicable regulatory authorities, where such explicit approval is required. Where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter that is three months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise prescribed by the laws or regulations of the applicable ERO governmental authorities. For Facility interconnections between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2007-06 – PRC-027-1	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the glossary.

Terms:

Interconnected Facilities: BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities.

Protection System Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Coordination for Performance During Faults**

2. **Number:** PRC-027-1

3. **Purpose:** To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2 Facilities:

   Protection Systems installed at Interconnected Facilities.

5. **Background:**

On December 7, 2006, the NERC Planning Committee approved the assessment of Reliability Standard PRC-001 – System Protection Coordination, prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF noted problems with the applicability to entities and vagueness of requirements in the existing PRC-001-1 reliability standard. The SPCTF concluded that the deficiencies of Reliability Standard PRC-001-1 were magnified by having requirements that addressed coordination of protection functions and capabilities in the operating and planning timeframes. Consequently, the SPCTF recommended that the requirements for the operating horizon and planning horizon be clearly delineated, and possibly divided into two standards.

The NERC Standards Committee approved a Standard Authorization Request that included the modifications noted by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC SDT) posted an initial draft of Reliability Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC SDT attempted to address all issues identified by the SPCTF assessment of PRC-001-1. The SPC SDT responded to the comments from the initial posting of PRC-001-2, and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC Quality Review (QR) in December 2010. Based on the results from the QR, and after informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to follow the SPCTF recommendation and focus their knowledge and expertise on developing a new results-based standard, concentrating on the reliability aspects (the coordination of new and existing protective systems in the planning horizon) associated with Requirements R3 and R4 of PRC-001-1. These aspects of coordination are incorporated and enhanced in the proposed Reliability Standard PRC-027-1 – Protection System Coordination for Performance During Faults with the stated purpose:

> *"To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."*

PRC-001-1 contained a non-specific training requirement (Requirement R1), three operating time frame requirements (Requirements R2, R5 and R6), and two planning requirements (Requirements R3 and R4). The SPC SDT transferred the responsibility of addressing the operating Requirements R2, R5, and R6 to the SDT for Project 2007-03 Real-time Operations, charged with revising the TOP group of reliability standards. The Project 2007-03 SDT retired Requirements R2, R5, and R6 of PRC-001-1 because they address data and data requirements that are included in the proposed Reliability Standard TOP-003-2. The SPC SDT is incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 in a new standard (as recommended by the SPCTF assessment), and focusing on the performance of Protection Systems during Faults. Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) will be retired upon appropriate regulatory approval of the proposed standards PRC-001-3 and PRC-027-1. The SPC SDT recommends that Requirement R1 remain in PRC-001-2, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard.

Additionally, the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address "the appropriate use of time delays in relays," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination.

Other Aspects of coordination of Protection Systems addressed by other Projects:

Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects.

- Underfrequency Load shedding programs are addressed by PRC-006-1 (Project 2007-01 Underfrequency Load Shedding – pending FERC approval) and generator performance during frequency excursions is being addressed by PRC-024-1 in Project 2007-09 Generator Verification.
- Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed by PRC-024-1 in Project 2007-09, Generator Verification.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is being addressed by PRC-019-1 in Project 2007-09.

- Transmission relay loadability is addressed in PRC-023-1 and, pending FERC approval, PRC-023-2.
- Generator relay loadability will be addressed by Phase 2 of Relay Loadability: Generation, in Project 2010-13.2.
- Protective relay response during power swings will be addressed in Phase 3 of Project 2010-13.3, Relay Loadability.
- Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and will be improved in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

The SPC SDT believes that including these other aspects of protection coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

1.1. Perform a Protection System Study for each Interconnected Facility to verify that Protection Systems remove from service only those Elements required to isolate Faults as follows:

1.1.1 Within 36 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Facility exists that was performed on or subsequent to June 18, 2007.

1.1.2 Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.

1.1.3 When proposing or being notified of a change at the Interconnected Facility, as described in Requirement R3, Part 3.1 or Part 3.3, unless the entity can demonstrate such a study is not required.

1.2. Provide to each affected Interconnected Facility owner a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the Protection System(s) reviewed, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each Protection System Study.

Rationale for R1:

Part 1.1 Protection System Studies are necessary to verify coordination of Protection Systems for existing and new Interconnected Facilities. The SDT defines the term "Interconnected Facilities" as "BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities."

Part 1.1.1 Protection System studies performed after June 18, 2007 (the effective date of PRC-001-1) and in accordance with PRC-001-1 are sufficient to meet Requirement R1, Part 1.1.1. The SDT believes that 36 months is an appropriate period of time for entities to perform the studies required where no study exists. The SDT has no evidence there is widespread miscoordination between Interconnected Facilities that warrants a shorter time frame.

Part 1.1.2 The SDT believes that 6 months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater Fault current deviation, where such conditions may warrant a new Protection System Study, or to justify why no such study is needed, i.e., when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current.

Part 1.1.3 The SDT believes that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, or to justify why no such study is needed. The SDT believes that specifying a time frame for performing studies associated with Requirement R3 is unnecessary because notification of such a change may occur weeks or years prior to the change. The initiating entity has the incentive to provide the identified information as soon as possible to ensure timely implementations.

Part 1.2 The requirement provides for the communication of the results of a Protection System Study to allow the interconnected owner to review the results. The SDT believes to properly ensure coordination of Protection Systems of Interconnected Facilities all entities need to assess the study results. The SDT believes that 90 calendar days is a reasonable time for the entity to provide the results of the Protection System Study performed in accordance with Requirement R1 to the Interconnected Facility owner.

M1. Acceptable evidence for Requirement R1, Part 1.1 and its subparts is a dated Protection System Study, or the summary results of each Protection System Study (either in hard copy or electronic file formats) meeting the time frames specified in Parts 1.1.1. and 1.1.2., or documentation demonstrating why a study is not required for changes described in Parts 1.1.2. and 1.1.3.

M2. Acceptable evidence for Requirement R1, Part 1.2. is dated documentation demonstrating each affected entity received, within the specified time frame, the summary results of each Protection System Study (hard copy or electronic file formats) sent, pursuant to Requirement R1, Part 1.2.

R2. For each Interconnected Facility, each Transmission Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

2.1. Perform a short circuit study to determine the present Fault current values, not less than once every 24 months.

2.2. Calculate the percent deviation between the Fault current values (single line to ground and 3-phase for the bus(s) or Element(s) under consideration) used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation:

$$\%\,Deviation = \left(\frac{Vscs - Vpss}{Vpss}\right) x\ 100$$

Where: V_{scs} = Fault current value from present short circuit study

And: V_{pss} = Fault current value used in the most recent Protection System Study

2.3. Where the calculation performed, pursuant to Requirement R2, Part 2.2, indicates a deviation in Fault current of 10% or greater, notify each owner of the Interconnected Facility, at which the 10% or greater deviation applies, within 30 calendar days after identification.

M3. Acceptable evidence for R2, Part 2.1 is dated documentation (hard copy or electronic file formats) containing the present Fault current values from the short circuit study for each Interconnected Facility analyzed.

M4. Acceptable evidence for R2, Part 2.2 is dated documentation (hard copy or electronic file formats) that identifies the percent deviation from the most recent Protection System Study Fault current values determined by

Rationale for R2: This requires a periodic review of Fault currents and notification to the applicable entities when deviations occur that meet the Requirement R2 criteria. It is important that Interconnected Facility owners are kept aware of changes that could affect proper performance of their Protection Systems. The Transmission Owner is identified as the entity responsible for performing the Fault current studies because they maintain the data necessary to perform the studies. The SDT determined that 10% was an appropriate point at which to require notification, based on the fact that Protection System elements that can be affected by Fault current are typically set with margins above 10%.

Part 2.1 Short circuit databases are customarily updated annually, so the SDT believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation. The SDT believes studies associated with changes that would affect the coordination in less time would be triggered by other requirements in this standard.

Part 2.2 The SDT is requiring this formula to assure a consistent approach is used by each Transmission Owner when calculating the percent deviation in Fault current vales.

Part 2.3 The SDT believes the 30-day time frame is reasonable for sending notification(s) to the interconnected entity(s).

the formula pursuant to Part 2.2.

M5. Acceptable evidence for R2, Part 2.3 is documentation (hardcopy or electronic file formats) demonstrating identification of a deviation in Fault current values 10% or greater, along with documentation (hard copy or electronic file formats) demonstrating each affected entity received notification of such within the specified timeframe.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility, the details (e.g., project schedule, protective relaying scheme types and settings) as follows: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

> Rationale for R3: This requires the transfer of appropriate information to the entities of each Interconnected Facility due to circumstances identified in Parts 3.1 3.2, and 3.3.
>
> Part 3.1 The reliability objective of this requirement is to enable the process of conducting Protection System Studies by ensuring that the information is provided to the Interconnected Facility owner(s) in a timely manner. The SDT believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. This requirement also pertains to changes identified as a result of studies performed in Part 1.1.
>
> Part 3.2 The purpose of this requirement is to provide a means for an entity to receive requested information from an interconnected owner in a timely manner in order to perform a Protection System Study, as required in Parts 1.1.1, 1.1.2, 1.1.3. The SDT believes 30 calendar days after receipt of the request is a sufficient amount of time to provide this information. The requirement also provides some flexibility for the parties involved to determine an otherwise agreed-to schedule, if appropriate.
>
> Part 3.3 The SDT believes 30 calendar days after the conditions noted in Parts 3.3.1 and 3.3.2 is sufficient time to provide the information.

3.1. For any change or additions listed below; either at an existing or new Interconnected Facility, or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities.

- New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios
- Changes to line lengths and/or conductor size or spacing
- Additions, removals, or replacements of transmission system Element(s)
- Changes to generator unit(s), including replacements, re-ratings, and impedances
- Replacement of the generator step-up transformer(s)

3.2. According to an agreed-upon schedule with a Transmission Owner, Generator Owner, or Distribution Provider, or absent such an agreement, within 30 calendar days of receiving a request for information.

3.3. Within 30 calendar days after:

3.3.1 Corrections are made when Protection System errors are found during Misoperation investigations, commissioning, or maintenance activities.

3.3.2 Emergency replacements are made due to failures of Protection System components.

M6. Acceptable evidence for R3, Part 3.1 is documentation (hard copy or electronic file formats) demonstrating each affected entity received project details for the changes identified in the bulleted list. Evidence may include, but is not limited to, a summary of the future project or technical specifications of the proposed changes.

M7. Acceptable evidence for R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was delivered according to the agreed-upon schedule, or within 30 calendar days absent such an agreement.

M8. Acceptable evidence for R3, Part 3.3 and its subparts is dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the changes made pursuant to Parts 3.3.1 and 3.3.2. was received within 30 calendar days.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Within 90 calendar days after receipt, confirm agreement with the summary results of a Protection System Study, as described in Requirement R1, Part 1.2.

4.2. Prior to the in-service date of any planned change at the Interconnected Facility, confirm the affected Interconnected Facility owners agree with the Protection System(s) changes, as described in Requirement R3, Part 3.1.

4.3. Within 30 calendar days after receipt:

4.3.1 Confirm the Protection System(s) changes are acceptable pursuant to notification received per Requirement R3, Part 3.3.1.

4.3.2 Confirm the Protection System(s) changes are acceptable pursuant to notification received per Requirement R3, Part 3.3.2.

Rationale for R4: This requirement ensures owners of Interconnected Facilities confirm that the Protection System(s) applied on each of its Interconnected Facilities is acceptable per the conditions identified in Parts 4.1, 4.2, and 4.3.

Part 4.1 The SDT believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to resolve differences and reach agreement.

Part 4.2 The SDT believes that proposed modifications (including project schedules) to Interconnected Facilities, as described in Requirement R3, Part 3.1, must be communicated and agreed to prior to the in-service date. Agreement assures that the coordination of Protection Systems for Interconnected Facilities is achieved.

Part 4.3 The SDT believes 30 calendar days is a reasonable time for the owners of existing Interconnected Facilities to resolve differences and reach agreement for the conditions noted in Parts 4.3.1 and 4.3.2. Note: Parts 4.3.1 and 4.3.2 reference Requirement R3, Parts 3.3.1 and 3.3.2 which pertain to corrective or Emergency changes.

M9. Acceptable evidence for R4, Parts 4.1, 4.2, and 4.3 is dated documentation (hardcopy or electronic file formats) demonstrating confirmation was achieved within the respective time frame(s).

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity; or if the Responsible Entity is owned, operated or controlled by the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e., another Regional Entity) to be responsible for compliance enforcement.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System at an Interconnected Facility shall keep data or evidence to show compliance with Requirements R1, R2, R3, and R4, and Measures M1 through M9, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System at an Interconnected Facility is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity performed a Protection System Study on an Interconnected Facility per R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Study on an Interconnected Facility per R1, Part 1.1.2, or documented why a study was not required, but was late by less than or equal to 10 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by 10 calendar days or less.	The responsible entity performed a Protection System Study on an Interconnected Facility per R1, Part 1.1.1, but was late by more than 30 calendar days. OR The responsible entity performed a Protection System Study on an Interconnected Facility per R1, Part 1.1.2, or documented why a study was not required, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity performed a Protection System Study on an Interconnected Facility per R1, Part 1.1.2, or documented why a study was not required, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity performed a Protection System Study on an Interconnected Facility per R1, Part 1.1.2, or documented why a study was not required but was late by more than 30 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 30 calendar days. OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The responsible entity failed to perform a Protection System Study on an Interconnected Facility per R1, Parts 1.1.1, 1.1.2, or 1.1.3, or document why a study was not required. OR The responsible entity failed to provide Protection System Study results in accordance with R1, Part 1.2.
R2	Long-term Planning	Medium	The Transmission Owner performed a short circuit study, as described in R2, Part 2.1, but was late by less than or equal to 30 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 40 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 40 calendar days but less than or equal to 50 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 50 calendar days. OR The Transmission Owner failed to perform a short circuit study, as described in R2, Part 2.1. OR The Transmission Owner failed to calculate the percent deviation between the Fault currents, according to the formula designated in

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner notified the Interconnected Facility owner of the changes in Fault currents, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner notified the Interconnected Facility owner of the changes in Fault currents, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner notified the Interconnected Facility owner of the changes in Fault currents, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	R2, Part 2.2. OR The Transmission Owner notified the Interconnected Facility owner of the changes in Fault currents, but was late by more than 30 calendar days. OR The Transmission Owner failed to notify the Interconnected Facility owner of the changes in Fault currents.
R3	Operations Planning	Medium	The responsible entity provided the requested information per R3, Part 3.2, but was late by 10 calendar days or less.	The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity failed to provide information to the owners of the Interconnected Facilities for any proposed change identified in R3.1. OR The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 30 calendar days.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by 10 calendar days or less.	OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the requested information.
R4	Operations Planning	Medium	The responsible entity confirmed agreement with the summary results of the Protection System Study per R4, Part 4.1, but was late by 10 calendar days or less.	The responsible entity confirmed agreement with the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity confirmed agreement with the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity confirmed agreement with the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 30 calendar days. OR The responsible entity failed to confirm agreement with the summary results of the Protection System Study per R4, Part 4.1. OR The responsible entity failed to confirm acceptance of the planned changes pursuant to R4, Part 4.2

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The responsible responded to the confirmation request per R4, Part 4.3, but was late by 10 calendar days or less.	OR The responsible responded to the confirmation request per R4, Part 4.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The responsible responded to the confirmation request per R4, Part 4.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	prior to implementation of those changes. OR The responsible responded to the confirmation request per R4, Part 4.3, but was late by more than 30 calendar days. OR The responsible entity failed to respond to the confirmation request per R4, Part 4.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

This requirement directs the performance of Protection System Studies for every Interconnected Facility to verify coordination of existing Protection Systems where no recent study exists or when Facility configuration or Fault current deviations of 10% or more have occurred. In developing the language to define Protection System Study, the System Protection Coordination Standard Drafting Team (SPC SDT) considered various reference books discussing protective relaying theory and application, along with the following description of "coordination of protection" from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Using the reference material cited above as guidance, the SDT defined the term Protection System Study for use within the PRC-027-1 Reliability Standard as:

> "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults."

Protection System Studies comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), and adequate directional polarizing quantities.

The SDT believes applicable entities should have a documented Protection System Study for each Interconnected Facility to validate the Protection Systems perform in a manner consistent with the purpose of this Standard. Additionally, the SDT believes that 36 months is an appropriate amount of time for entities to perform the initial studies expected under this requirement. This period considers the time some entities may require to create project scopes, acquire proposals, and secure contracts to hire external resources that may be needed to perform the studies. The SDT also has no evidence there is widespread miscoordination between Interconnected Facilities that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.

It should be noted that Protection System studies performed after June 18, 2007 (the effective date of PRC-001-1) are sufficient to meet Requirement R1.

Parts 1.1.2 and 1.1.3 further direct that Protection System Studies must be completed under the following two circumstances:

1. After notification of an identified 10% or greater deviation in Fault current, the notified entities must perform a new Protection System Study of the Interconnected Facility or document why a study is not required. The SDT recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater deviation in Fault current may not necessitate a new Protection System Study be performed; therefore this part of the requirement includes the statement, "… unless the entity can demonstrate that such a study is not required." The SDT believes the six-month time frame associated with this requirement represents a reasonable period to perform the studies that are required after identification by the 24-month Fault current review.
2. After proposing or being notified of a change at an Interconnected Facility, entities must perform a new Protection System Study, or document why a study is not required. The SDT recognizes that, based on the scope of the proposed change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new Protection System Study be performed; therefore this part of the requirement includes the statement, "… unless the entity can demonstrate that such a study is not required." The SDT believes that specifying a single time frame for evaluation of the wide variety of conditions that may be associated with a particular change is not appropriate. This is because the SDT sees the entity initiating any change as having the incentive to move this along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2.

Requirement R1, Part 1.2 requires the entity performing the Protection System Study to provide a summary of the study results to the affected owners of Protection Systems applied at Interconnected Facilities. As guidance, the SDT lists the following inputs and results of a Protection System Study that may be included in the summary provided pursuant to this requirement:

1. Data used to determine Fault currents in performing the study, along with a listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Interconnected Facility under study.
2. A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Interconnected Facility, and were reviewed for coordination of protective relays as part of the study.
3. A listing of any issues associated with the relay settings of the other owner(s) at the Interconnected Facility that were identified by the study.

4. Any proposed revisions to a Protection System or its protective relay settings that were identified by the study.

Requirement R2:

The SDT investigated various inputs that would trigger a review of the existing Protection System Studies and determined, through the experience of the SDT members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated Protection System Study may be necessary. These variations could result from the accumulation of incremental changes over time. This requirement mandates a periodic review of Fault currents and includes the calculation of the percent deviation between the Fault current values used in the most recent Protection System Study and the present Fault current values indicated by the short circuit study performed pursuant to this requirement. This calculation is necessary to identify Fault current changes that must be communicated in accordance with Requirement R2, Part 2.3.

Polling of SDT membership and various protection engineering committees indicates that short circuit databases are customarily updated annually. Based on this information, the SDT believes that requiring a 24-month periodic review of Fault currents provides entities additional flexibility to schedule and perform these studies and calculate the percent deviation, as described in Requirement R2, Part 2.2. The SDT believes studies associated with changes that would affect the coordination in less than 24 months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.3 further directs the Transmission Owner to, within 30 calendar days, inform Interconnected Facility owners when short circuit studies indicate that 10% deviations in Fault current have occurred at the Interconnected Facility. The SDT believes the 30-day time frame associated with this requirement is reasonable for sending notification to the interconnected entity(s) and is consistent with other NERC reliability standards.

In Requirement R2, the Transmission Owner is identified as the functional entity responsible for performing the Fault current studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.

Requirement R3:

This requires the Interconnected Facility owners to evaluate the impact to their Protection Systems due to proposed changes by requiring the registered functional entity initiating the changes to provide the details to the other affected entities of the Interconnected Facility. Documentation provided to these other owners may include, but is not limited to, power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings. The recipient will incorporate the applicable information into its Protection System Studies to evaluate whether changes are required.

The list of applicable changes provided in Requirement R3, Part 3.1 is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. The SDT recognizes that Facility changes at other locations can impact the Protection System Study of the Interconnected Facilities; e.g., the addition of a large autotransformer bank or generator not directly associated with the Interconnected Facilities. The SDT believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the SDT sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2.

Requirement R3, Part 3.2 allows for entities to agree upon a schedule, appropriate to the circumstances, for providing the details needed to conduct a Protection System Study or, absent such agreement, within 30 days of a request for this information. This requirement provides a means for entities to receive requested information in a timely manner. In consideration of circumstances where the information may not be readily available or may be incomplete due the retirement of personnel, the purging of records, change of ownership, etc., it also provides the flexibility of mutually agreeing to a schedule for exchanging information. The SDT believes 30 calendar days after receipt of the request is a sufficient amount of time to provide the requested information where no other agreement exists.

Additionally, this requirement includes a provision for providing details associated with changes to the previously agreed-upon coordination when: (1) Protection System errors are found during misoperation investigations, commissioning, or maintenance activities; (2) Emergency replacements are made due to failures of Protection System components. Based upon the limited number of instances that would occur under such circumstances, the SDT believes 30 calendar days after determining that changes are required is an appropriate time frame for providing the associated details to affected entities.

Requirement R4:

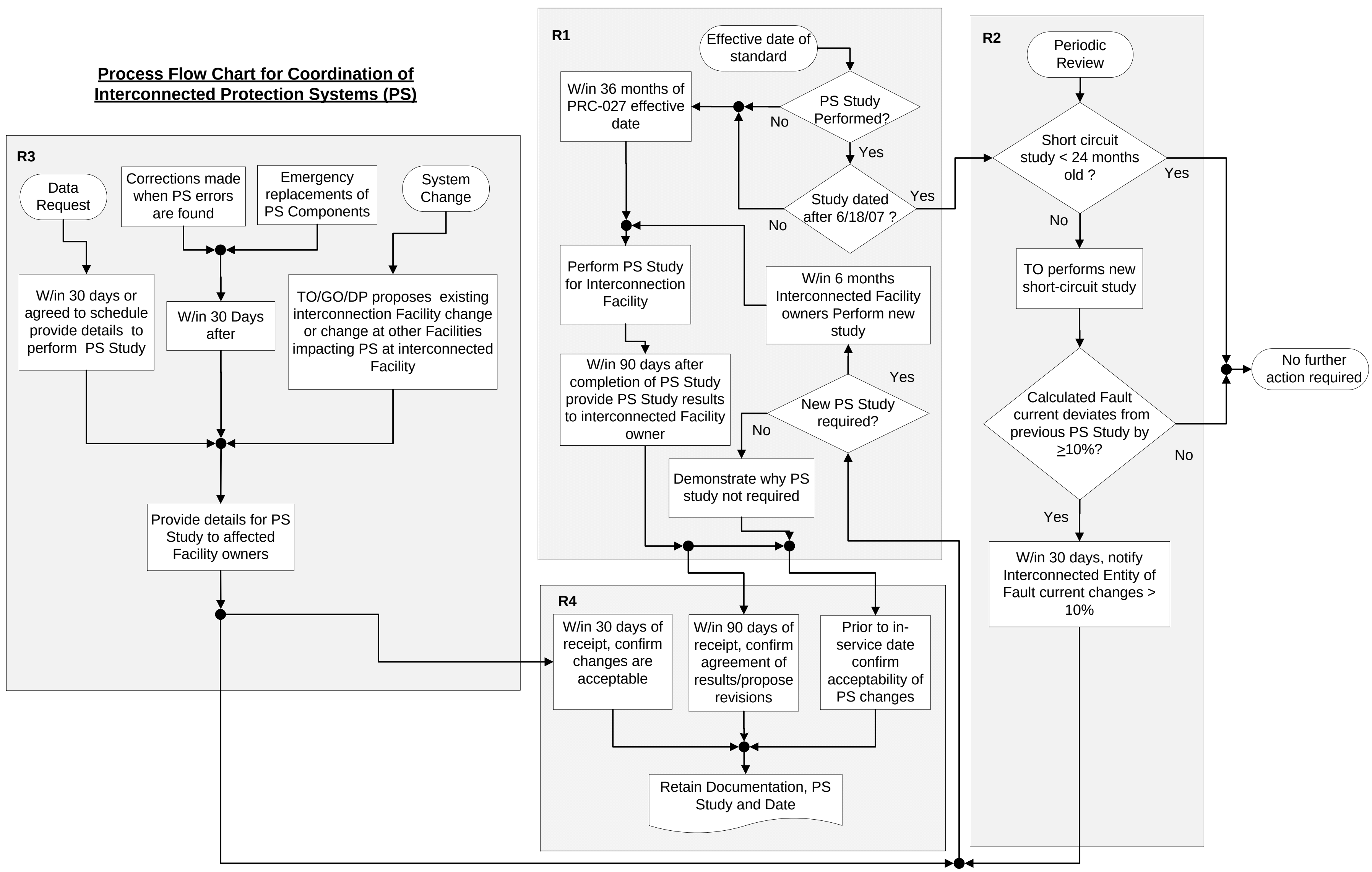
The reliability objective of this requirement is to bring the process of Protection System coordination full circle by gaining the confirmation of interconnected entities that their Protection Systems are coordinated consistent with the purpose of this standard. Cooperative participation of Interconnected Facility owners in communicating Protection System(s) design, and study results will achieve coordination of Protection Systems for reliable operation of the BES during Faults.

Requirement R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to confirm agreement with the summary results of a Protection System Study, as described in Requirement R1, Part 1.2; or absent such agreement, propose revisions to achieve acceptable results. The SDT believes 90 calendar days after receipt of the results of a Protection System Study provides a reasonable time for the owners of Interconnected Facilities to resolve differences and reach agreement that their Protection Systems are coordinated.

Requirement R4, Part 4.2 directs entities to confirm that planned changes described in Requirement 3.1 are acceptable prior to the in-service date of those changes. The purpose of this requirement is to assure the effects that planned changes have on Protection Systems at Interconnected Facilities have been considered by all affected entities.

Requirement R4, Parts 4.3.1 and 4.3.2 direct confirmation within 30 calendar days that changes are acceptable when corrections are made due to Protection System errors found during misoperation investigations, commissioning, or maintenance activities, or when Emergency replacements are made due to failures of Protection System components. Based upon the limited number of instances that would occur under such circumstances, the SDT believes 30 calendar days provides adequate time for achieving such agreement.

Process Flow Chart: Below is a complete representation of the process, including the relationships between requirements:



Example Process

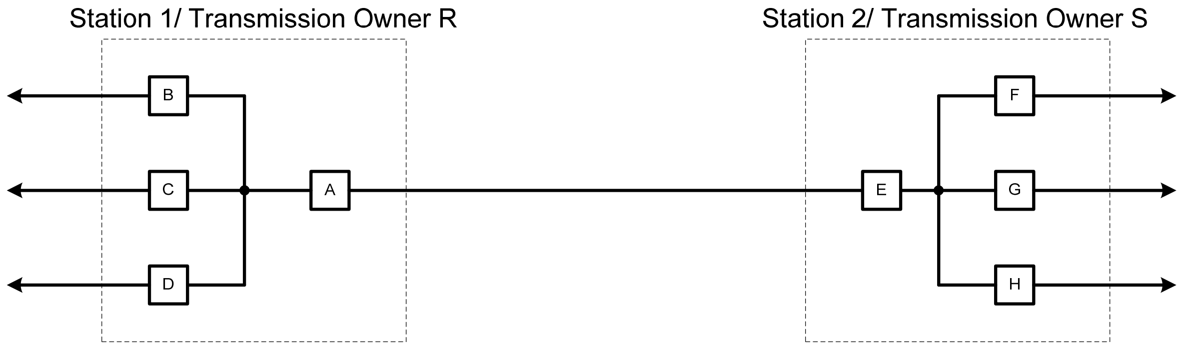
An example of the interaction between entities required to gather the information to perform an accurate study is below.

- The initiating entity (Entity A) will contact the interconnected entity (Entity B) and request up-to-date Protection System information.
- Upon receipt of the above request for information, Entity B will provide the information within 30 calendar days, or an agreed upon time frame.
- Entity A will perform a Protection System Study using the information received.
- Entity A will provide a summary of the results of the study to Entity B within 90 calendar days of completing the Protection System Study.
- Entity B will review the summary information and, within 90 calendar days of receiving the study results from Entity A, confirm agreement that coordination is achieved.
    - In cases where the study reveals that changes to Protection Systems are needed, Entity B would propose to Entity A revisions that achieve acceptable results.
- Documentation of the final agreement is required prior to implementation of planned changes.

Diagrams

Introduction: The diagrams below are intended to provide guidance related to the responsibilities associated with the purpose of this standard between owners of Interconnected Facilities. After the reviews and prior to implementation of the changes, the owners must reach agreement on the final settings to achieve coordination of the Protection Systems.

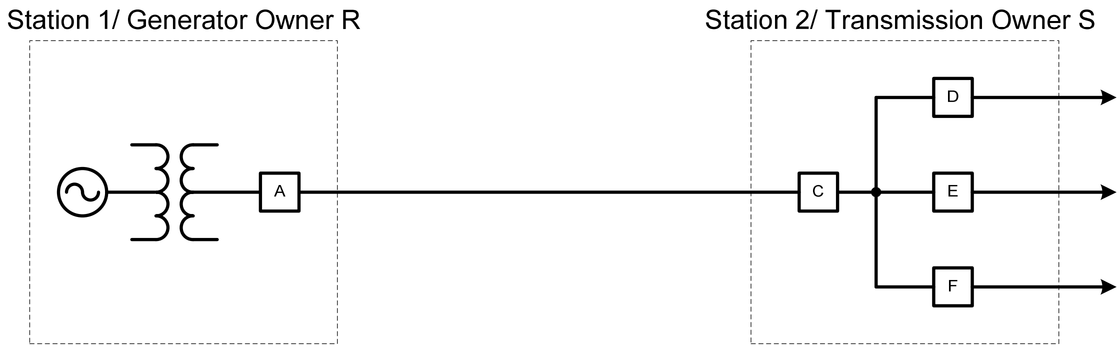
Figure 1



In Figure 1 above, the interconnecting Element between the Transmission Interconnected Facilities (Station 1 – Transmission Owner R and Station 2 – Transmission Owner S) is the transmission line between Breakers A and E.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 1, the responsibility for Owner S is to verify that the Protection System settings associated with Breaker A (provided by Owner R) do not result in coordination issues with the Protection System settings associated with Breakers E, F, G, and H. Likewise, the responsibility for Owner R is to verify that the Protection System settings associated with Breaker E (provided by Owner S) do not result in coordination issues with the Protection System settings associated with Breakers A, B, C, and D.

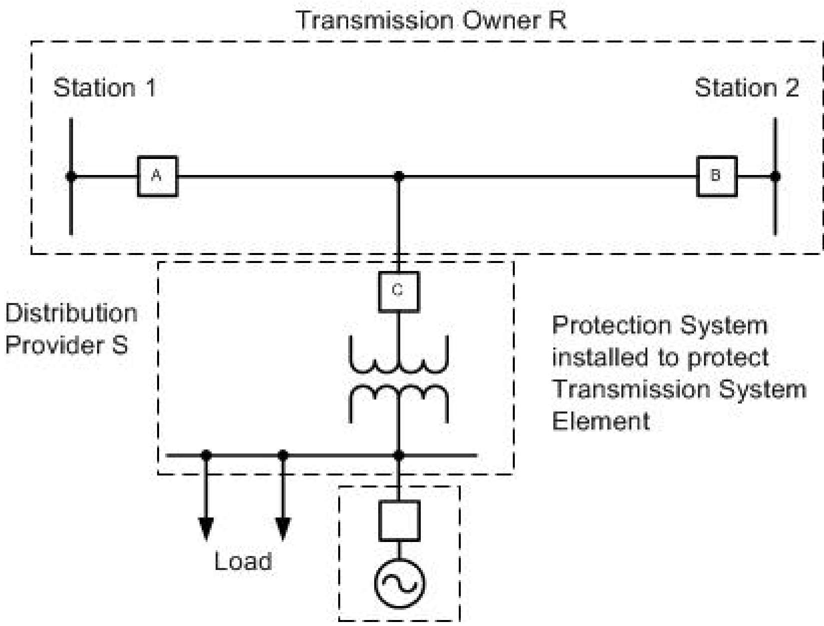
Figure 2



In Figure 2 above, the interconnecting Element between the Transmission to Generation Interconnected Facilities (Station 1 – Generation Owner R and Station 2 – Transmission Owner S) is the transmission line or bus between Breakers A and C.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 2, the responsibility for Transmission Owner S is to verify that the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems do not result in coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, the responsibility for Generation Owner R is to verify that the Protection System settings associated with Breaker C (provided by Owner S) do not result in coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

Figure 3

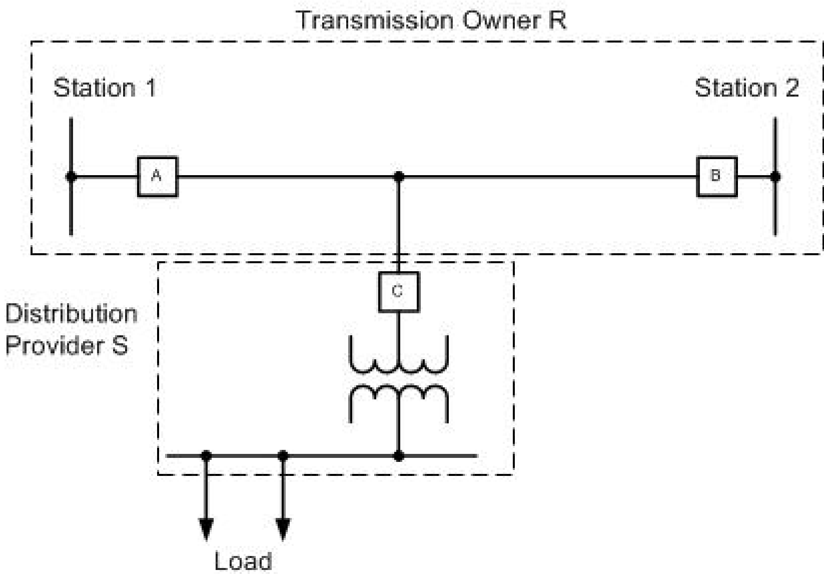


In Figure 3 above, the interconnecting Element between the Transmission Owner to Distribution Provider (with a generator) Interconnected Facilities (Transmission Owner R line between Breakers A and B – Distribution Provider S) is the transmission line or tap between the line and Breaker C.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 3, the responsibility for Transmission Owner R is to verify that the Protection System settings associated with Line Breaker C (provided by Distribution Provider S) and the generator Protection Systems do not result in coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2. Likewise, the responsibility for Distribution Provider S is to verify that the Protection System settings associated with Breakers A and B (provided by Owner R) do not result in coordination issues with the Protection System settings associated with Breaker C and the generator Protection Systems. In order to perform this verification, it will be necessary that the Generator Owner provide Distribution Provider S with its generator Protection System settings.

Note: A Protection System Study is required per this standard for this example if a Protection System at the Distribution Provider's substation is designed to protect BES transmission system Elements.

Figure 4

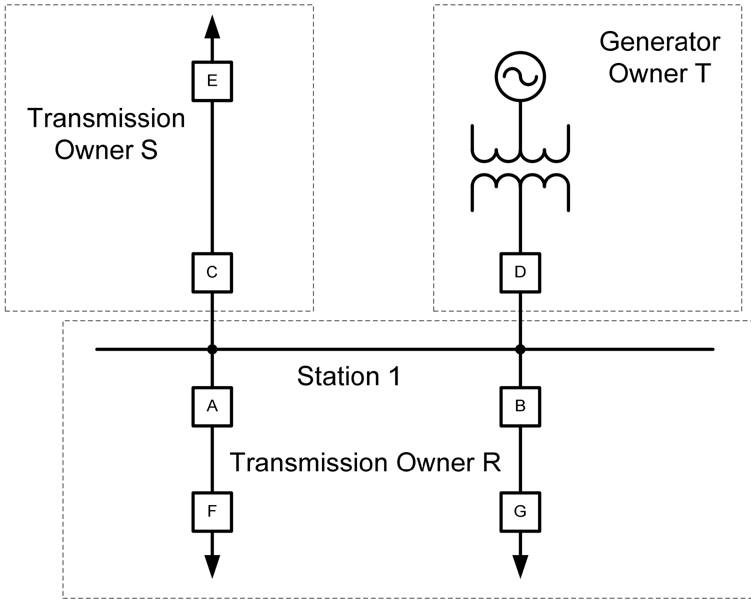


In Figure 4 above, the interconnecting Element between the Transmission Owner to Distribution Provider Interconnected Facilities (Transmission Owner R line between Breakers A and B – Distribution Provider S) is the transmission line or tap between the line and Breaker C.

Note: No specific Protection System Study is required per this standard for this example since the Protection System at the Distribution Provider's substation is not designed to protect BES transmission system Elements.

Figure 5

Transmission/Generation Facility with Multiple Owners



In Figure 5 above, the interconnecting Element between the Transmission Owners R and S and the Generation Owner T is the common Transmission bus. In this example, Transmission Owner S and Generator Owner T are not directly interconnected to each other at Transmission Station 1, and all direct interconnections are between Owner R and each of the other Owners connected to the bus.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 5:

The responsibility for Owner R is to verify that the Protection System settings associated with Breaker C, E, D, and the generator Protection System (provided by Owners S or T) do not result in coordination issues with the Protection System settings associated with Breakers A, B.

The responsibility for Owner S is to verify that the Protection System settings associated with Breakers A, F, B, G, D, and the generator Protection System (provided by Owners R or T) do not result in coordination issues with the Protection System settings associated with Breaker C. To perform this verification, it will be necessary that Transmission Owner R provide Owner S with its settings for Breakers A, F, B, and G, as well as the settings for Breaker D and generator Protection System settings provided to Owner R by Generator Owner T.

The responsibility for Owner T is to verify that the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R or S) do not result in coordination issues with the Protection System settings associated with Breaker D or the Protection Systems associated with generator Protection Systems. In order to perform this verification, it will be necessary that Transmission Owner R provide Generator Owner T with its settings for Breakers A, F, G, and B, as well as the settings for Breaker C and E provided to Owner R by Transmission Owner S.

Unofficial Comment Form for 1st Draft of PRC-027-1: Protection System Coordination for Performance During Faults

Project 2007-06

Please **DO NOT** use this form to submit comments on the 1st draft of the standard for Protection System Coordination for Performance During Faults. Comments must be submitted by **July 5, 2012**. If you have questions please contact Al McMeekin at al.mcmeekin@nerc.net or by telephone at 803-530-1963. Please submit comments here.

http://www.nerc.com/filez/standards/System_Protection_Project_2007-06.html

Background Information:

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC SDT) posted an initial draft of the Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC SDT attempted to address the planning and non-operational issues identified in the assessment of PRC-001-1 performed by the NERC System Protection and Control Task Force (SPCTF) as well as the operating time frame issues identified in FERC Order 693. These operating time frame requirements involved detecting Protection System failures, informing operators and taking quick corrective actions; consequently, the SPC SDT transferred the Order 693 directives associated with Requirements R2, R5 and R6 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standards associated within that project. Additionally, the SPC SDT determined that Requirement R1 in PRC-001-1 (a requirement for the Transmission Operator, Balancing Authority and Generator Operator to "be familiar with the purpose and limitations of protection system schemes applied in its area") is unrelated to coordination of protection systems and belongs in another project. The two remaining requirements, Requirements R3 and R4 of PRC-001-1 address the coordination of new and existing protective systems. These aspects of coordination are incorporated in the proposed standard PRC-027-1 Protection System Coordination for Performance during Faults.

The SPC SDT responded to the comments from the initial posting of PRC-001-2 and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC quality review in December 2010, which resulted in substantial changes to the standard. After informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team members decided to focus their knowledge and expertise on developing a new results-based standard with the stated purpose completely within the scope of the original SAR: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."

The SPC SDT is presenting the first draft of PRC-027-1 for stakeholder review and comment.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT established the following Purpose for this standard: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."

   Do you agree with this Purpose? If not, please provide specific suggestions for changes to the purpose in the comment area.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT assigned the Applicability of PRC-027-1 to Transmission Owners, Generator Owners and Distribution Providers that own the Protection Systems applied at the Interconnected Facilities that require coordination for isolating generation and Transmission Faults. Are you aware of other functional entities that should be included in the Applicability? If so, please provide specific suggestions in the comment area and the reason for including those functional entities.

   ☐ Yes

   ☐ No

   Comments:

3. In Requirement R1, the SDT allowed a responsible entity 36 months to have a documented Protection System Study completed for each Interconnected Facility if the responsible entity does not already have a Protection System Study for that Interconnected Facility performed on or subsequent to June 18, 2007 (the effective date of PRC-001-1). Do you agree with this time frame? If not, please provide specific suggestions for change in the comment area.

   ☐ Yes

   ☐ No

   Comments:

4. In Requirement R2, the SDT established a +/- 10 % change in an Interconnected Facility's Fault current value as a criterion for notifying interconnected entities to give the interconnected entity a "heads up" that a review of the existing documented Protection System Study may be warranted.

   Do you agree with the +/- 10 % Fault current threshold for initiating this review? If not, please provide an alternative means along with a technical justification for determining a threshold.

   ☐ Yes

☐ No

Comments:

5. In Requirement R3, the SDT included a list of proposed changes that impact the coordination of Protection Systems and would initiate a need to inform other entities. Do you agree that this is an appropriate and inclusive list? If not, please provide specific suggestions for additions or deletions with your reasoning(s) in the comment area.

   ☐ Yes

   ☐ No

   Comments:

6. In Requirement R4, the SDT required that agreement must be reached prior to implementation of proposed Protection System changes except under the conditions identified in Requirement 3, Part 3.3. Do you agree with this need? If not, please specify reasons in the comment area.

   ☐ Yes

   ☐ No

   Comments:

7. In Requirement R4, the SDT established a 90 day time frame for responding to a request for agreement with a Protection System Study. Do you agree with this time frame? If not, please provide specific suggestions with your reasoning(s) in the comment area.

   ☐ Yes

   ☐ No

   Comments:

8. The team included VRFs, VSLs, and Time Horizons with this posting. Do you agree with the assignments? If not, please provide specific suggestions for change.

   ☐ Yes

   ☐ No

   Comments:

9. If you have any other comments **<u>that you have NOT provided in response to the above questions</u>**, please provide them here. (Please do not repeat comments that you provided elsewhere.)

   Comments:

Project 2007-06 System Protection Coordination Mapping Document

Mapping Document Showing Translation of PRC-001-2 – System Protection Coordination to PRC-027-1 – Protection System Coordination for Performance During Faults

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	Retained	NA
R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R2.1** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. **R2.2** Each Transmission Operator shall	PRC-027-1, R1, R3, & R4 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Study for each Interconnected Facility to verify that Protection Systems remove from service only those Elements required to isolate Faults as follows: **1.1.3.** When proposing or being notified of a change at the Interconnected Facility as described in Requirement R3, Part 3.1 or Part 3.3, unless the entity can demonstrate such a study is not required. **1.2.** Provide to each affected Interconnected Facility owner, a summary

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.		of the results of each Protection System Study performed pursuant to this requirement, (including at a minimum, the Protection System(s) reviewed, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each Protection System Study. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility the details (e.g., project schedule, protective relaying scheme types and settings) as follows: **3.1.** For any change or additions listed below; either at an existing or new Interconnected Facility, or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities. • New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios • Changes to line lengths and/or conductor size or spacing • Additions, removals, and/or replacements of transmission system Element(s) • Changes to generator unit(s), including replacements, re-ratings, and impedances

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		• Replacement of the generator step-up transformer(s) **3.2.** According to an agreed-upon schedule with a Transmission Owner, Generator Owner, or Distribution Provider; or absent such an agreement, within 30 calendar days of receiving a request for information. **3.3.** Within 30 calendar days after: **3.3.1.** Corrections are made when Protection System errors are found during Misoperation investigations, commissioning, or maintenance activities. **3.3.2.** Emergency replacements are made due to failures of Protection System components. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **4.2.** Prior to the in-service date of any planned change at the Interconnected Facility, confirm the affected Interconnected Facility owners agree with the Protection System(s) changes, as described in Requirement R3, Part 3.1. **4.3.** Within 30 calendar days after receipt: **4.3.1.** Confirm the Protection System(s) changes are acceptable pursuant to notification received per Requirement R3, Part 3.3.1.

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Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		4.3.2. Confirm the Protection System(s) changes are acceptable pursuant to notification received per Requirement R3, Part 3.3.2.
R3. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	PRC-027-1, R1, R2, R3, & R4 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Study for each Interconnected Facility to verify that Protection Systems remove from service only those Elements required to isolate Faults as follows: **1.1.1.** Within 36 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Facility exists that was performed on or subsequent to June 18, 2007. **1.1.2.** Within six calendar months after determining, or being notified of, a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required. **1.2.** Provide to each affected Interconnected Facility owner a summary of the results of each Protection System Study performed pursuant to this requirement, (including at a minimum, the Protection System(s) reviewed, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each Protection System Study. **R2.** For each Interconnected Facility, each Transmission Owner shall:

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		2.1. Perform a short circuit study to determine the present Fault current values, not less than once every 24 months. **2.2.** Calculate the percent deviation between the fault current values (single line to ground and 3-phase for the bus(s) or Element(s) under consideration) used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1 using the following equation: Where: V_{scs} = Fault current value from present short-circuit study And: V_{pss} = Fault current value used in the most recent Protection System Study **2.3.** Where the calculation performed pursuant to Requirement R2, Part 2.2 indicates a deviation in fault current of 10% or greater, notify each owner of the Interconnected Facility at which the 10% or greater deviation applies, within 30 calendar days after identification. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility the details (e.g., project schedule, protective relaying scheme types and settings) as follows:

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		3.2. According to an agreed-upon schedule with a Transmission Owner, Generator Owner, or Distribution Provider; or absent such an agreement, within 30 calendar days of receiving a request for information. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **4.1.** Within 90 calendar days after receipt, confirm agreement with the summary results of a Protection System Study, as described in Requirement R1, Part 1.2.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-06 System Protection Coordination
PRC-027-1

Approvals Requested

- PRC-027-1 Protection System Coordination for Performance During Faults
- PRC-001-3 System Protection Coordination

Applicable Entities

Standard	Applicable Entities					
	TO	GO	DP	TOP	GOP	BA
PRC-027-1: Protection System Coordination for Performance During Faults	X	X	X			
PRC-001-3: System Protection Coordination				X	X	X

Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definitions:

Interconnected Facilities: BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities.

Protection System Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.

Background

On December 7, 2006, the NERC Planning Committee approved the assessment of Standard PRC-001-1 (System Protection Coordination) prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF asserted:

> *"The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the 'operating horizon, operations planning horizon, and planning horizon' protection coordination issues, the deficiencies in the current standard are magnified."*

And further:

"The SPCTF… recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards."

The Standard Committee approved the Standard Authorization Request with modifications by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

With the development of the proposed Reliability Standard PRC-027-1, the Standard Drafting Team (SDT) for Project 2007-06 – System Protection Coordination, has followed the observations and recommendation of the NERC SPCTF assessment of PRC-001-1 which had six requirements. The SDT accomplishes this by:

1. Incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) and moving those requirements into a new standard (as recommended by the SPCTF assessment), focusing on the performance of Protection Systems during Faults.
2. Assigning responsibility for coordination of Protection Systems during Faults to the appropriate functional entities – the Protection System equipment owners, specifically: Transmission Owners, Generator Owners, and Distribution Providers.
3. Transferring the responsibility of addressing the three operating horizon Requirements R2, R5, and R6 of PRC-001-1 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standard(s) within that project. (The NERC Board of Trustees approved these changes proposed by the Project 2007-03 team when it approved PRC-001-2 on May 9, 2012.)
4. Leaving the legacy Requirement R1 of PRC-001-2 in PRC-001-3 (thereby not creating a reliability gap) until it is incorporated into a new or revised reliability standard.

Effective Date of New or Revised Standards and Definitions

PRC-027-1 - Protection System Coordination for Performance During Faults

PRC-027-1 shall become effective on the first day of the first calendar quarter that is three months beyond the date that this standard is approved by applicable regulatory authorities, where such explicit approval is required. Where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter that is three months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise prescribed by the laws or regulations of the applicable ERO governmental authorities. For Facility Interconnections between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.

PRC-001-3 – System Protection Coordination

Same effective date as PRC-027-1.

Effective Date for Definitions

The two proposed definitions (Interconnected Facilities and Protection System Study) shall become effective at the same time as PRC-027-1.

Retirement:

PRC-001-2 – Protection System Coordination shall be retired at midnight the day before PRC-001-3 becomes effective.

Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 — Protection System Coordination for Performance During Faults

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1 — Protection System Coordination for Performance During Faults.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

The System Protection Coordination Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric

System; or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures; nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and, therefore, concentrated its approach on the reliability impact of the requirements.

PRC-027-1 Protection System Coordination for Performance During Faults is a new Reliability Standard with the stated purpose: *"To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems do not remove power system Elements from service except for those required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."* PRC-027-1 has four (4) requirements that incorporate and enhance the reliability intent of Requirements R3 and R4 of PRC-001-1. The new standard addresses the aspects of coordination for new Protection Systems, as well as changes to existing Protection Systems. The new requirements describe the steps necessary to achieve coordination. The coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner, and reaching agreement on Protection System settings and schemes.

All four requirements are assigned VRFs of Medium. The assignment of the Medium VRFs was made based on the premise that failure to perform these coordination activities by themselves would not directly cause or contribute to bulk power system instability, separation, or a Cascading sequence of failures. For a requirement to be assigned a "High" VRF, there should be the expectation that failure to meet the required performance "will" result in instability, separation, or Cascading failures, and this is usually not the case when an applicable entity fails to 'coordinate' activities. While the SDT agrees that, under some circumstances, it is possible that a failure to perform the required activities may hinder the coordination process; however, the failure would not, by itself, result in instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-027-1, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to perform a Protection System Study for each Interconnected Facility to verify that Protection Systems remove from service only those Elements required to isolate Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R1 is similar in scope to Requirements R2, R3 and R4, as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R1 directs that Protection System Studies are performed for every Interconnected Facility to verify coordination of existing Protection Systems. This requirement is similar to Requirement R1 of FAC-002-1, which also requires studies be performed and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to perform a Protection System Study for each Interconnected Facility to verify that Protection Systems remove from service only those Elements required to isolate Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R1 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed a Protection System Study on an Interconnected Facility per R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Study on an Interconnected Facility per R1, Part 1.1.2, or documented why a study was not required but was late by less than or equal to 10 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by 10 calendar days or less.	The responsible entity performed a Protection System Study on an Interconnected Facility per R1, Part 1.1.1, but was late by more than 30 calendar days. OR The responsible entity performed a Protection System Study on an Interconnected Facility per R1, Part 1.1.2, or documented why a study was not required but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity performed a Protection System Study on an Interconnected Facility per R1, Part 1.1.2, or documented why a study was not required but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity performed a Protection System Study on an Interconnected Facility per R1, Part 1.1.2, or documented why a study was not required but was late by more than 30 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 30 calendar days. OR The responsible entity failed to perform a Protection System Study on an Interconnected Facility per R1, Parts 1.1.1, 1.1.2, or 1.1.3, or document why a study was not required. OR The responsible entity failed to provide Protection System Study results in accordance with R1, Part 1.2.

VSL Justifications – PRC-027-1, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to periodically review, calculate the percent deviation in fault current values used as inputs for updating Protection System Study(s), and to notify Interconnected Facility owners of requisite deviations in fault currents, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R2 is similar in scope to Requirements R1, R3 and R4, as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R2 facilitates a periodic review of Fault currents and notification of Interconnected Facility owners. This requirement is similar to Requirement R6 of BAL-005-0.2b in that it also requires the comparison of calculated data and possible notification of other entities; and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to periodically review, calculate the percent deviation in fault current values used as inputs for updating Protection System Study(s) and to notify Interconnected Facility owners of requisite deviations in fault currents, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R2 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by less than or equal to 30 calendar days. OR The Transmission Owner notified the Interconnected Facility owner of the changes in Fault currents, but was late by less than or equal to 10 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 40 calendar days. OR The Transmission Owner notified the Interconnected Facility owner of the changes in Fault currents, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 40 calendar days but less than or equal to 50 calendar days. OR The Transmission Owner notified the Interconnected Facility owner of the changes in Fault currents, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 50 calendar days. OR The Transmission Owner failed to perform a short circuit study, as described in R2, Part 2.1. OR The Transmission Owner failed to calculate the percent deviation between the Fault currents according to the formula designated in R2, Part 2.2. OR The Transmission Owner notified the Interconnected Facility owner of the changes in Fault currents, but was late by more than 30 calendar days. OR The Transmission Owner failed to notify the Interconnected Facility owner of the changes in Fault currents.

VSL Justifications – PRC-027-1, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to communicate proposed changes that modify the conditions used in the coordination of Protection Systems of the Interconnected Facilities could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R3 is similar in scope to Requirements R1, R2 and R4 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R3 facilitates the provision of pertinent information regarding proposed changes that could impact the coordination of Protection Systems at Interconnected Facilities. This requirement is similar to Requirement R2 of FAC-009-1 in that it also requires the provision of reliability data to other pertinent functional entities, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to communicate proposed changes that modify the conditions used in the coordination of Protection Systems of the Interconnected Facilities could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R3 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R3			
Lower	**Moderate**	**High**	**Severe**
The responsible entity provided the requested information per R3, Part 3.2, but was late by 10 calendar days or less. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by 10 calendar days or less.	The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity failed to provide information to the owners of the Interconnected Facilities for any proposed change identified in R3.1. OR The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the requested information.

VSL Justifications – PRC-027-1, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to reach agreement for proposed changes that modify the conditions used in the coordination of Protection Systems of the Interconnected Facilities could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R4 is similar in scope to Requirements R1, R2 and R3 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R4 mandates responsible entities reach agreement on Protection System Study results or proposed changes to Protection System(s) prior to implementation. This requirement is similar to Requirement R2 of PRC-023-1 in that it also requires agreement be obtained, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to reach agreement for proposed changes that modify the conditions used in the coordination of Protection Systems of the Interconnected Facilities could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R4 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity confirmed agreement with the summary results of the Protection System Study per R4, Part 4.1, but was late by 10 calendar days or less. OR The responsible responded to the confirmation request per R4, Part 4.3, but was late by 10 calendar days or less.	The responsible entity confirmed agreement with the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible responded to the confirmation request per R4, Part 4.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity confirmed agreement with the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible responded to the confirmation request per R4, Part 4.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity confirmed agreement with the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 30 calendar days. OR The responsible entity failed to confirm agreement with the summary results of the Protection System Study per R4, Part 4.1. OR The responsible entity failed to confirm acceptance of the planned changes pursuant to R4, Part 4.2, prior to implementation of those changes. OR The responsible responded to the confirmation request per R4, Part 4.3, but was late by more than 30 calendar days. OR The responsible entity failed to respond to the confirmation request per R4, Part 4.3.

VSL Justifications – PRC-027-1, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Technical Justification

PRC-027-1 Protection System Coordination for Performance During Faults

The purpose of the proposed PRC-027-1 reliability standard is to coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC reliability standards. This purpose is consistent with NERC's goal to create and implement reliability standards that enable or support at least one of the eight defined Reliability Principles. The requirements of the proposed PRC-027-1 reliability standard directly support the following Reliability Principles:

> Reliability Principle 1 – Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions, as defined in the NERC Standards.
>
> Reliability Principle 3 – Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
>
> Reliability Principle 7 – The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Reliability Standard PRC-001-1, as assessed by the NERC System Protection and Control Task Force (SPCTF) in its report of December 7, 2006, does not assign responsibility to the appropriate functional entities, contains several fundamental flaws within the requirements, and mixes training, operational, and planning related requirements in one standard. Primarily, as stated in the conclusion of this assessment, the SPCTF asserts:

> *"The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the "operating horizon," "operations planning horizon," and "planning horizon" protection coordination issues, the deficiencies in the current standard are magnified."*

And further:

> *"The SPCTF… recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards."*

With the development of the proposed PRC-027-1 reliability standard, the Standard Drafting Team (SDT) for Project 2007-06 – System Protection Coordination has followed the observations and recommendation of the NERC SPCTF assessment of PRC-001-1. In the proposed standard, the SDT properly assigns the applicable functional entities and builds upon the planning horizon requirements of PRC-001-1 that are applicable to Protection System coordination related to system Faults (Requirements R3 and R4). The SDT accomplishes this by:

1. Incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 into a new standard (as recommended by the SPCTF assessment), focusing on the performance of Protection Systems during Faults. Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) will be retired upon appropriate regulatory approval of the proposed standards PRC-001-3 and PRC-027-1.)

2. Assigning responsibility to the appropriate functional entities – the Protection System equipment owners, specifically: Transmission Owners, Generator Owners, and Distribution Providers.

3. Transferring the responsibility of addressing the three operating horizon Requirements R2, R5, and R6 of PRC-001-1 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standard(s) within that project.

   Note: The proposed disposition of Requirements R2, R5, and R6 of PRC-001-1 is posted on the Project 2007-03 page. The Project 2007-03 SDT is recommending retirement of Requirements R2, R5, and R6 of PRC-001-1 because they address data and data requirements which are covered in TOP-003-2. For Project 2007-03, the SDT included a redlined version of PRC-001-1 and a clean version of PRC-001-2 with the conforming changes, along with a mapping document and implementation plan describing the translation of the legacy requirements into TOP-003-2.

4. Leaving the legacy Requirement R1 of PRC-001-1 in PRC-001-2 (thereby not creating a reliability gap) until it is incorporated into a new or revised reliability standard.

The proposed PRC-027-1 reliability standard includes four requirements that build upon the reliability objectives of Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2), and further provide a defense-in-depth strategy for ensuring Bulk Power System (BPS) reliability associated with Protection System coordination for Interconnected Facilities between owners by:

- Requiring a documented Protection System Study of the Protection Systems applied on the Interconnected Facilities between owners, within 36 months of the effective date of the proposed standard.
- Establishing criteria for a periodic review of the previously-documented Protection System Study of the Protection Systems applied on the Interconnected Facilities between owners.
- Continuing the requirement that installing new Protection Systems and making changes to existing Protection Systems will require interaction between owners to ensure no coordination issues exist prior to implementation of these changes.
- Establishing, where applicable, time frames for one entity to respond to requests by other entities for information and/or concurrence related to Protection System Studies associated with Interconnected Facilities.

Individually, the requirements of the proposed PRC-027-1 reliability standard construct a defense-in-depth strategy and improve upon the existing PRC-001-1 Reliability Standard Requirements R3 and R4, (now R2 and R3 of PRC-001-2) as detailed by the following:

Requirement R1:

This requirement directs that Protection System Studies are performed for every Interconnected Facility defined as: “Facilities that are electrically joined by one or more Element(s) and are owned by different functional entities;” to verify coordination of existing Protection Systems where no recent study exists or when Facility configuration or Fault current deviations of 10% or more have occurred. In developing the language to define a Protection System Study, the SDT considered various reference books discussing protective relaying theory and application, along with the following description of “coordination of protection” from the pending revision of IEEE C37.113 Guide for Protective Relay Applications to Transmission Lines:

> *“The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault.”*

Using the reference material cited above as guidance, the SDT defines the term Protection System Study as:

“A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.”

Protection System Studies comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), and adequate directional polarizing quantities.

The SDT believes applicable entities should have a documented Protection System Study for each Interconnected Facility to validate the Protection Systems perform in a manner consistent with the purpose of this standard. Additionally, the SDT believes that 36 months is an appropriate amount of time for entities to perform the initial studies expected under this requirement. This period considers the time some entities may require to create project scopes, acquire proposals, and secure contracts to hire external resources that may be needed to perform the studies. The SDT also has no evidence there is widespread miscoordination between Interconnected Facilities that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.

It should be noted that Protection System Studies performed after June 18, 2007 (the effective date of PRC-001-1) are sufficient to meet Requirement R1.

Requirement R1, Parts 1.1.2 and 1.1.3 further direct that Protection System Studies must be completed under the following two circumstances:

1. After notification of an identified 10% or greater deviation in Fault current, the notified entities must perform a new Protection System Study of the Interconnected Facility, or document why a study is not required. The SDT recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater deviation in Fault current may not necessitate a new Protection System Study be performed; therefore this part of the requirement includes the statement, "… unless the entity can demonstrate that such a study is not required," The SDT believes the six months time frame associated with this requirement represents a reasonable amount of time to perform the studies required after identification by the 24-month Fault current review.

2. After proposing or being notified of a change at an Interconnected Facility, entities must perform a new Protection System Study, or document why a study is not required. The SDT recognizes that, based on the scope of the proposed change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new Protection System Study be performed; therefore, this part of the requirement includes the statement, "… unless the entity can demonstrate that such a study is not required." The SDT believes that specifying a single time frame for evaluation of the wide variety of conditions that may be associated with a particular change is not appropriate. This is because the SDT sees the entity initiating any change as having the incentive to move this along in a timely fashion to keep the associated project on schedule and to confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2.

Requirement R1, Part 1.2 requires that the entity performing the Protection System Study provide a summary of the study results to the affected owners of Protection Systems applied at Interconnected Facilities. As guidance, the SDT lists the following inputs and results of a Protection System Study that may be included in the summary provided pursuant to this requirement:

1. Data used to determine Fault currents in performing the study along with a listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Interconnected Facility under study.
2. A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Interconnected Facility and were reviewed for coordination of protective relays as part of the study.
3. A listing of any issues associated with the relay settings of the other owner(s) at the Interconnected Facility that were identified by the study.

4. Any proposed revisions to a Protection System or its protective relay settings that were identified by the study.

Requirement R2:

The SDT investigated various inputs that would trigger a review of the existing Protection System Studies, and determined through the experience of the SDT members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated Protection System Study may be necessary. These variations could result from the accumulation of incremental changes over time. This requirement mandates a periodic review of Fault currents and includes the calculation of the percent deviation between the Fault current values used in the most recent Protection System Study and the present Fault current values indicated by the short circuit study performed pursuant to this requirement. This calculation is necessary to identify Fault current changes that must be communicated in accordance with Requirement R2, Part 2.3.

Polling of SDT membership and various protection engineering committees indicates that short circuit databases are customarily updated annually. Based on this information, the SDT believes that requiring a 24-month periodic review of Fault currents provides entities additional flexibility to schedule and perform these studies and calculate the percent deviation as described in Requirement R2, Part 2.2. The SDT believes studies associated with changes that would affect the coordination in less than 24 months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.3 further directs the Transmission Owner to, within 30 calendar days; inform Interconnected Facility owners when short circuit studies indicate that 10% deviations in Fault current have occurred at the Interconnected Facility. The SDT believes the 30-day time frame associated with this requirement is reasonable for sending notification to the interconnected entity(s), and is consistent with other NERC Reliability Standards.

In Requirement R2, the Transmission Owner is identified as the functional entity responsible for performing the Fault current studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.

Requirement R3:

This requires the Interconnected Facility owners to evaluate the impact to their Protection Systems due to proposed changes by requiring the registered functional entity initiating the changes to provide the details to the other affected entities of the Interconnected Facility. Documentation provided to these other owners may include, but is not limited to, power system configurations; protection schemes; schematics; instrument transformer ratios; type of relay(s); communication equipment applied for protection; and Protection System settings. The recipient will incorporate the applicable information into its Protection System Studies to evaluate whether changes are required.

The list of applicable changes provided in Requirement R3, Part 3.1 is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. The SDT recognizes that other Facility changes not directly associated with the interconnection can impact the Protection System Study of the Interconnected Facilities; e.g., the addition of a large autotransformer bank or generator not directly associated with the Interconnected Facilities. The SDT believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the SDT sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part P.2.

Requirement R3, Part 3.2 allows for entities to agree upon a schedule, appropriate to the circumstances, for providing the details needed to conduct a Protection System Study; or absent such agreement, within 30 days of a request for this information. This requirement provides a means for entities to receive requested information in a timely manner. In consideration of circumstances where the information may not be readily available or may be incomplete due the retirement of personnel, the purging of records, change of ownership, etc., it also provides the flexibility of mutually agreeing to a schedule for exchanging information. The SDT believes 30 calendar days after receipt of the request is a sufficient amount of time to provide the requested information where no other agreement exists.

Additionally, this requirement includes a provision for providing details associated with changes to the previously-agreed upon coordination when: (1) Protection System errors are found during Misoperation investigations, commissioning, or maintenance activities; (2) Emergency replacements are made due to failures of Protection System components. Based upon the limited number of instances that would occur under such circumstances, the SDT believes 30 calendar days after determining that changes are required is an appropriate time frame for providing the associated details to affected entities.

Requirement R4:

The reliability objective of this requirement is to bring the process of Protection System coordination full circle by gaining the confirmation of interconnected entities that their Protection Systems are coordinated consistent with the purpose of this standard. Cooperative participation of Interconnected Facility owners in communicating Protection System(s) design and study results will achieve coordination of Protection Systems for reliable operation of the BES during Faults.

Requirement R4, Part 4.1 directs applicable entities to confirm, within 90 days of receipt, agreement with the summary results of a Protection System Study, as described in Requirement R1, Part 1.2; or absent such agreement, propose revisions to achieve acceptable results. The SDT believes 90 calendar days after receipt of the results of a Protection System Study provides a reasonable time for the owners of Interconnected Facilities to resolve differences and reach agreement that their Protection Systems are coordinated.

Requirement R4, Part 4.2 directs entities to confirm that planned changes described in Requirement 3.1 are acceptable prior to the in-service date of those changes. The purpose of this requirement is to assure the effects that planned changes have on Protection Systems at Interconnected Facilities have been considered by all affected entities.

Requirement R4, Parts 4.3.1 and 4.3.2 direct confirmation within 30 calendar days that changes are acceptable when corrections are made due to Protection System errors found during Misoperation investigations, commissioning, or maintenance activities, or when Emergency replacements are made due to failures of Protection System components. Based upon the limited number of instances that would occur under such circumstances, the SDT believes 30 calendar days provides adequate time for achieving such agreement.

Conclusion

The proposed PRC-027-1 reliability standard builds upon the effectiveness of Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2). It also corrects the assignment of applicability of these requirements to the owners of the applicable Protection Systems. It establishes a structured roadmap of entity-to-entity communication and a process to ensure proper coordination of Protection Systems applied on Interconnected Facilities. Within this roadmap, as each requirement is combined with the other requirements, the standard achieves a defense-in-depth strategy for assuring proper coordination of Protection Systems applied on Interconnected Facilities. As such, the proposed PRC-027-1 reliability standard satisfies the overall objective of a true, reliability-based standard appropriate for approval of the NERC Board of Trustees and other applicable regulatory authorities.

Standards Announcement

Project 2007-06 – System Protection Coordination

Ballot Pools Forming: May 21 – June 19, 2012
Formal Comment Period Open: May 21 – July 5, 2012

Upcoming Ballots:
Initial Ballot and Non-Binding Poll: June 26 – July 5, 2012

Now Available

A formal comment period for PRC-027-1 – Protection System Coordination for Performance During Faults is open through 8 p.m. Eastern on Thursday, July 5, 2012 and ballot pools are forming through 8 a.m. Tuesday, June 19, 2012.

Instructions for Joining Ballot Pool(s)

Two ballot pools are being formed. Registered Ballot Body members must join the first ballot pool to be eligible to vote in balloting of standard PRC-027-1, and a second, separate ballot pool to be eligible to cast an opinion in the non-binding poll of the associated VRFs and VSLs. Registered Ballot Body members may join each of these ballot pools at the following page: Join Ballot Pool

Note that there is no requirement to join both of these ballot pools; Registered Ballot Body members who are only interested in voting during the ballot of the standard are not required to join the ballot pool for the non-binding poll, and vice versa.

During the pre-ballot windows, members of the ballot pools may communicate with one another by using their "ballot pool list servers." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The ballot pool list servers for these ballot pools are:

Initial ballot: bp-2007-06_PRC-027-1_in@nerc.com
Non-binding poll: bp-2007-06_NB_PRC-027-1_in@nerc.com

The ballot pools are open **through 8 a.m. Eastern on Tuesday, June 19, 2012.**

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Thursday, July 5, 2012**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Commenters and voters must submit comments through the electronic comment form. Due to modifications to NERC's balloting software, voters are no longer able to submit comments via the balloting software.

Next Steps

An initial ballot of the standard and non-binding poll of the associated VRF/VSLs will be conducted beginning on Tuesday, June 26, 2012 through 8 p.m. Eastern on Thursday, July 5, 2012.

Background

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC SDT) posted an initial draft of the Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC SDT attempted to address the planning and non-operational issues identified in the assessment of PRC-001-1 performed by the NERC System Protection and Control Task Force (SPCTF) as well as the operating time frame issues identified in FERC Order 693. These operating time frame requirements involved detecting Protection System failures, informing operators and taking quick corrective actions; consequently, the SPC SDT transferred the Order 693 directives associated with Requirements R2, R5 and R6 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standards associated within that project. Additionally, the SPC SDT determined that Requirement R1 in PRC-001-1 (a requirement for the Transmission Operator, Balancing Authority and Generator Operator to "be familiar with the purpose and limitations of protection system schemes applied in its area") is unrelated to coordination of protection systems and belongs in another project. The two remaining requirements, Requirements R3 and R4 of PRC-001-1 address the coordination of new and existing protective systems. These aspects of coordination are incorporated in the proposed standard PRC-027-1 Protection System Coordination for Performance During Faults.

The SPC SDT responded to the comments from the initial posting of PRC-001-2 and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC quality review in December 2010, which resulted in substantial changes to the standard. After informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team members decided to focus their knowledge and expertise on developing a new results-based standard with the stated purpose completely within the scope of the original SAR: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."

PRC-027-1 is a results-based reliability standard that is important part of the ERO's strategic goal to develop technically sufficient standards with requirements that provide clear and unambiguous performance expectations and reliability benefits.

The SPC SDT is presenting the first draft of PRC-027-1 for stakeholder review and comment.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend out thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Thursday, July 5, 2012**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Commenters and voters must submit comments through the electronic comment form. Due to modifications to NERC's balloting software, voters are no longer able to submit comments via the balloting software.

Next Steps
An initial ballot of the standard and non-binding poll of the associated VRF/VSLs will be conducted beginning on Tuesday, June 26, 2012 through 8 p.m. Eastern on Thursday, July 5, 2012.

Background
The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC SDT) posted an initial draft of the Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC SDT attempted to address the planning and non-operational issues identified in the assessment of PRC-001-1 performed by the NERC System Protection and Control Task Force (SPCTF) as well as the operating time frame issues identified in FERC Order 693. These operating time frame requirements involved detecting Protection System failures, informing operators and taking quick corrective actions; consequently, the SPC SDT transferred the Order 693 directives associated with Requirements R2, R5 and R6 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standards associated within that project. Additionally, the SPC SDT determined that Requirement R1 in PRC-001-1 (a requirement for the Transmission Operator, Balancing Authority and Generator Operator to "be familiar with the purpose and limitations of protection system schemes applied in its area") is unrelated to coordination of protection systems and belongs in another project. The two remaining requirements, Requirements R3 and R4 of PRC-001-1 address the coordination of new and existing protective systems. These aspects of coordination are incorporated in the proposed standard PRC-027-1 Protection System Coordination for Performance During Faults.

The SPC SDT responded to the comments from the initial posting of PRC-001-2 and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC quality review in December 2010, which resulted in substantial changes to the standard. After informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team members decided to focus their knowledge and expertise on developing a new results-based standard with the stated purpose completely within the scope of the original SAR: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."

PRC-027-1 is a results-based reliability standard that is important part of the ERO's strategic goal to develop technically sufficient standards with requirements that provide clear and unambiguous performance expectations and reliability benefits.

The SPC SDT is presenting the first draft of PRC-027-1 for stakeholder review and comment.

NERC

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend out thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Atlanta, GA 30326
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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2007-06 – System Protection Coordination

Initial Ballot and Non-Binding Poll Results

Now Available

An initial ballot of PRC-027-1 – Protection System Coordination for Performance During Faults and a non-binding poll of the associated VRFs/VSLs concluded Thursday, July 5, 2012.

Voting statistics for each ballot are listed below, and the Ballots Results page provides a link to the detailed results.

Approval	Non-binding Poll Results
Quorum: 84.24%	Quorum: 82.26%
Approval: 23.82%	Supportive Opinions: 25.19%

Next Steps

The drafting team will consider all comments submitted, and based on the comments will determine whether to make additional changes. If the drafting team decides to make substantive revisions, the drafting team will submit the revised standard and consideration of comments received for a quality review prior to posting for a parallel formal 30-day comment period and successive ballot.

Background

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC SDT) posted an initial draft of the Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC SDT attempted to address the planning and non-operational issues identified in the assessment of PRC-001-1 performed by the NERC System Protection and Control Task Force (SPCTF) as well as the operating time frame issues identified in FERC Order 693. These operating time frame requirements involved detecting Protection System failures, informing operators and taking quick corrective actions; consequently, the SPC SDT transferred the Order 693 directives associated with Requirements R2, R5 and R6 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standards associated within that project. Additionally, the SPC SDT determined that Requirement R1 in PRC-001-1 (a requirement for the Transmission Operator, Balancing Authority and Generator Operator to "be familiar with the purpose and limitations of protection system schemes applied in its area") is unrelated to coordination of protection systems and belongs in another project. The two remaining requirements, Requirements R3 and R4 of PRC-001-1 address the coordination of new and existing protective systems. These aspects of coordination are incorporated in the proposed standard PRC-027-1 Protection System Coordination for Performance During Faults.

Additional information is available on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

Ballot Results	
Ballot Name:	Project 2007-06 Initial Ballot PRC-027-1 June 2012_in
Ballot Period:	6/26/2012 - 7/5/2012
Ballot Type:	Initial
Total # Votes:	358
Total Ballot Pool:	425
Quorum:	**84.24 % The Quorum has been reached**
Weighted Segment Vote:	23.82 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	114	1	14	0.156	76	0.844	8	16
2 - Segment 2.	9	0.4	2	0.2	2	0.2	4	1
3 - Segment 3.	102	1	12	0.138	75	0.862	5	10
4 - Segment 4.	37	1	5	0.185	22	0.815	3	7
5 - Segment 5.	88	1	9	0.143	54	0.857	6	19
6 - Segment 6.	52	1	6	0.146	35	0.854	1	10
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	9	0.9	4	0.4	5	0.5	0	0
9 - Segment 9.	6	0.1	0	0	1	0.1	1	4
10 - Segment 10.	8	0.6	3	0.3	3	0.3	2	0
Totals	**425**	**7**	**55**	**1.668**	**273**	**5.332**	**30**	**67**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson		
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	ATCO Electric	Glen Sutton	Negative	
1	Austin Energy	James Armke	Negative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	

1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Pasadena	Marco A Sustaita	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Negative	
1	City Water, Light & Power of Springfield	Shaun Anders	Affirmative	
1	Clark Public Utilities	Jack Stamper	Negative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	Consumers Power Inc.	Stuart Sloan	Negative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Negative	
1	Duke Energy Carolina	Douglas E. Hils		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	El Paso Electric Company	Dennis Malone	Negative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis		
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	
1	Idaho Power Company	Molly Devine	Negative	
1	Imperial Irrigation District	Tino Zaragoza	Negative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JEA	Ted Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	LG&E Energy Transmission Services	Bradley C. Young	Negative	
1	Long Island Power Authority	Robert Ganley	Negative	
1	Los Angeles Department of Water & Power	John Burnett	Negative	
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Negative	
1	MEAG Power	Danny Dees	Abstain	
1	Metropolitan Water District of Southern California	Ernest Hahn	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Negative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Negative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Negative	
1	Northern Indiana Public Service Co.	Kevin M Largura		
1	NorthWestern Energy	John Canavan	Negative	
1	NStar Gas and Electric	John Robertson	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	

1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Negative	
1	PacifiCorp	Ryan Millard	Negative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Negative	
1	Portland General Electric Co.	John T Walker	Negative	
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Brett A. Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Negative	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Negative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Sierra Pacific Power Co.	Rich Salgo	Negative	
1	Snohomish County PUD No. 1	Long T Duong		
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Negative	
1	Trans Bay Cable LLC	Steven Powell	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	
1	Turlock Irrigation District	Esteban Martinez	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Negative	
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	
1	Wolverine Power Supply Coop., Inc.	Michelle Denike	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	ISO New England, Inc.	Kathleen Goodman	Abstain	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs	Negative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Negative	
3	Alameda Municipal Power	Douglas Draeger	Negative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	
3	Basin Electric Power Cooperative	Daniel Klempel	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blachly-Lane Electric Co-op	Bud Tracy	Negative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham	Negative	
3	Central Electric Power Cooperative	Adam M Weber		
3	Central Lincoln PUD	Steve Alexanderson	Negative	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		

3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Lodi, California	Elizabeth Kirkley	Negative	
3	City of Palo Alto	Eric R Scott	Affirmative	
3	City of Redding	Bill Hughes	Negative	
3	City of Ukiah	Colin Murphey	Negative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Clearwater Power Co.	Dave Hagen	Negative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Negative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Consumers Power Inc.	Roman Gillen	Negative	
3	Coos-Curry Electric Cooperative, Inc	Roger Meader	Negative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	El Paso Electric Company	Tracy Van Slyke	Negative	
3	Entergy	Joel T Plessinger	Abstain	
3	Fall River Rural Electric Cooperative	Bryan Case	Negative	
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	
3	Flathead Electric Cooperative	John M Goroski	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Georgia System Operations Corporation	Scott McGough	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter	Negative	
3	Lane Electric Cooperative, Inc.	Rick Crinklaw	Negative	
3	Lincoln Electric System	Jason Fortik	Negative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Northern Lights Inc.	Jon Shelby	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Negative	
3	Pacific Northwest Generating Cooperative	Rick Paschall	Negative	
3	PacifiCorp	Dan Zollner	Negative	
3	Pepco Holdings, Inc.	Mark R Jones	Negative	
3	Platte River Power Authority	Terry L Baker	Negative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Negative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	

3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	
3	Raft River Rural Electric Cooperative	Heber Carpenter	Negative	
3	Rutherford EMC	Thomas M Haire	Negative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salmon River Electric Cooperative	Ken Dizes	Negative	
3	Salt River Project	John T. Underhill	Negative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Umatilla Electric Cooperative	Steve Eldrige	Negative	
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power	Kevin Koloini	Negative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Negative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	
4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Pacific Northwest Generating Cooperative	Aleka K Scott	Negative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Southern Minnesota Municipal Power Agency	Richard L Koch	Negative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Turlock Irrigation District	Steven C Hill	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
4	WPPI Energy	Todd Komplin	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	

5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason	Negative	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	
5	City of Redding	Paul A. Cummings	Negative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Jennifer Eckels	Negative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex		
5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke		
5	Dominion Resources, Inc.	Mike Garton	Negative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Negative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne		
5	Imperial Irrigation District	Marcela Y Caballero	Negative	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Negative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Negative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Negative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame		
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Portland General Electric Co.	matt E jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Negative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema	Negative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	
5	South Carolina Electric & Gas Co.	Edward Magic		

5	Southeastern Power Administration	Douglas Spencer	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz		
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	TransAlta Corporation	Rebbekka McFadden	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	WPPI Energy	Steven Leovy	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox		
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	
6	City of Redding	Marvin Briggs	Negative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	
6	Constellation Energy Commodities Group	Donald Schopp	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil	Negative	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Negative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Negative	
6	Los Angeles Department of Water & Power	Brad Packer	Negative	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Scott L Smith	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Negative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	William T Moojen	Negative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	

6	Xcel Energy, Inc.	David F. Lemmons		
8		James A Maenner	Negative	
8		Roger C Zaklukiewicz	Negative	
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	California Energy Commission	William M Chamberlain		
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Midwest Reliability Organization	William S Smith	Negative	
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Project 2007-06 Non-binding Poll Results

Non-binding Poll Results	
Non-binding Poll Name:	Project 2007-06 Non-binding Poll for PRC-027-1
Poll Period:	6/26/2012 - 7/5/2012
Total # Votes:	320
Total Ballot Pool:	389
Summary Results:	82.26% of those who registered to participate provided an opinion or an abstention; 25.19% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson		
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	ATCO Electric	Glen Sutton	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Pasadena	Marco A Sustaita	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Negative	
1	City Water, Light & Power of Springfield	Shaun Anders	Affirmative	
1	Clark Public Utilities	Jack Stamper	Negative	
1	Colorado Springs Utilities	Paul Morland	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		

1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	El Paso Electric Company	Dennis Malone	Negative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis		
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	
1	Idaho Power Company	Molly Devine	Negative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JEA	Ted Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	LG&E Energy Transmission Services	Bradley C. Young	Negative	
1	Long Island Power Authority	Robert Ganley	Negative	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Negative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Kevin M Largura		
1	NorthWestern Energy	John Canavan	Negative	
1	NStar Gas and Electric	John Robertson	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	

1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Negative	
1	PacifiCorp	Ryan Millard	Abstain	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Negative	
1	Portland General Electric Co.	John T Walker	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Brett A. Koelsch	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Negative	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Negative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong		
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Trans Bay Cable LLC	Steven Powell	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	
1	Turlock Irrigation District	Esteban Martinez	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Negative	
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	
1	Wolverine Power Supply Coop., Inc.	Michelle Denike	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs	Abstain	

2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	Alabama Power Company	Richard J. Mandes	Negative	
3	Alameda Municipal Power	Douglas Draeger		
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Basin Electric Power Cooperative	Daniel Klempel	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber		
3	Central Lincoln PUD	Steve Alexanderson	Negative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Lodi, California	Elizabeth Kirkley	Negative	
3	City of Palo Alto	Eric R Scott		
3	City of Redding	Bill Hughes	Negative	
3	City of Ukiah	Colin Murphey	Negative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Negative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	El Paso Electric Company	Tracy Van Slyke	Negative	
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	
3	Flathead Electric Cooperative	John M Goroski	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Georgia System Operations Corporation	Scott McGough	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter	Negative	
3	Lincoln Electric System	Jason Fortik	Affirmative	

3	Los Angeles Department of Water & Power	Daniel D Kurowski	Negative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Negative	
3	PacifiCorp	Dan Zollner	Negative	
3	Platte River Power Authority	Terry L Baker	Negative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Negative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	
3	Rutherford EMC	Thomas M Haire	Negative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salmon River Electric Cooperative	Ken Dizes	Negative	
3	Salt River Project	John T. Underhill	Negative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Abstain	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power	Kevin Koloini	Negative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Negative	

4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Negative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Turlock Irrigation District	Steven C Hill	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
4	WPPI Energy	Todd Komplin	Negative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Phillip Porter		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Negative	

5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Jennifer Eckels	Negative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex		
5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke		
5	Dominion Resources, Inc.	Mike Garton		
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Negative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne		
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Abstain	
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Negative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Negative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame		
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	

5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Portland General Electric Co.	matt E jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Negative	
5	Puget Sound Energy, Inc.	Tom Flynn	Negative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema	Negative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southeastern Power Administration	Douglas Spencer	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz		
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	WPPI Energy	Steven Leovy	Negative	
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6	City of Redding	Marvin Briggs	Negative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	
6	Duke Energy	Greg Cecil	Negative	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Affirmative	

6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Negative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	Snohomish County PUD No. 1	William T Moojen	Negative	
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	
8		James A Maenner	Negative	
8		Roger C Zaklukiewicz	Negative	
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	California Energy Commission	William M Chamberlain		
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Midwest Reliability Organization	William S Smith	Negative	
10	New York State Reliability Council	Alan Adamson	Negative	

10	Northeast Power Coordinating Council	Guy V. Zito	Negative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Organization (47 Responses)
Group Name (29 Responses)
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Question 2 (69 Responses)
Question 2 Comments (76 Responses)
Question 3 (67 Responses)
Question 3 Comments (76 Responses)
Question 4 (66 Responses)
Question 4 Comments (76 Responses)
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Question 5 Comments (76 Responses)
Question 6 (63 Responses)
Question 6 Comments (76 Responses)
Question 7 (65 Responses)
Question 7 Comments (76 Responses)
Question 8 (48 Responses)
Question 8 Comments (76 Responses)
Question 9 (0 Responses)
Question 9 Comments (76 Responses)

Group
Dominion
Mike Garton
No
Dominion supports the stated purpose up to the comma. The qualifying language after the comma is ambiguous and not supported in the Requirements of this standard.
No
Yes
Yes
Yes
Yes
Yes
Dominion is concerned that a YES vote will also endorse the revision, also part of this project, to PRC-001-3, which is would then be reduced to only one requirement that is not measurable and does not contribute to the purpose of the standard. The Measure for the requirement has also been removed. The standard should be retired or mapped to another standard.
Individual
Michael Falvo
Independent Electricity System Operator
No
We agree with the first part of the purpose statement, but do not find it necessary to include the second part since “meeting the system performance specified within requirements established in

other approved NERC Reliability Standards" is universally true for all standards. No one single standard can assure reliability on its own; multiple standards must be complied with to meet one or more reliability objectives and performance targets. We suggest to remove the part "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".
No
Yes
No
We do not agree or disagree with the 10% deviation threshold. In the Technical Justification document, the SDT indicates that "The SDT investigated various inputs that would trigger a review of the existing Protection System Studies, and determined through the experience of the SDT members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated Protection System Study may be necessary." Lacking statistical or detailed studied results, this basis is as good as any. However, there does not appear to be any assessment made on the potential BES reliability risks when the Fault current deviates by less than 10%. Many Protection Systems' settings are linked to Fault current level and as such, deviation as low as a few percent may render a Protection relay not operating as intended. We suggest the STD to assess the risk of not conducting a verification study for the Protection Systems when Fault current deviates from past values at a lower range to either confirm that a 10% deviation would be a safe trigger, or revise it according to the findings of the risk assessment. (NTD: we may also suggest that a Protection System Study should be required for every BES modification that is in the electrical proximity of the Interconnected Facility and is expected to modify the Fault current levels.)
Yes
No
We agree with the need to provide an agreement to the study results and to confirm acceptability of the proposed changes (other than those conditions identified in Requirement 3, Part 3.3), but R4 is unclear in a number of aspects, as follows: 4.1 There is no requirement or provision for the receiving entities to express disagreement, with rationale, and R4 does not require resolving the differences. Both need to be added. 4.2 Based on the language in Part 4.1, we assume R4 applies to the receiving entities. Hence we interpret 4.2 to require the receiving entities to confirm with the sending (or the initiating) entities of their agreement with the proposed changes. In that vein, the wording in 4.1 "confirm the affected Interconnected Facility owners" is unclear as to who needs to confirm with whom. Suggest to reword 4.1 to: "Prior to the in-service date of any planned change at the Interconnected Facility, confirm with the Interconnected Facility owners that initiated the changes that agreement with the Protection System(s) changes as described in Requirement R3, Part 3.1. was reached." 4.3 requires that the receiving entities confirm with the initiating entities of the changes made under Part 3.3, for which prior agreements are not necessary or perhaps possible. However, there is no requirement or provision for the receiving entities to express a disagreement, with rationale, and suggest alternative setting changes, or resolve the differences. This needs to be provided.
Yes
Yes
We generally agree with the VRFs and the VSLs for the requirements as presented, but we have concerns with some of the requirements and hence reserve our comments until we see revisions made to these requirements.
1. As a general comment, we do not support defining new terms which have limited applications (e.g. for use in one or very few standard) and which are short and therefore can be equally effectively expressed in the requirement that the term or its intended meaning is used. Adding new terms to the NERC Glossary when not absolutely necessary creates unnecessary maintenance workload and dependency among standards that use the same term, making it far more difficult to revise a

standard without addressing the ripple effects. While we do not oppose to defining the term Interconnected Facilities as it serves to clarify and provide the boundary of the Facility, and we see its potential application to other standards, we disagree with defining the term “Protection System Study”. The definition contains an objective “operate in the desired sequence for clearing Faults” that should be stipulated in the standard requirements themselves. Further, as suggested below, the requirements that this term is used can be easily revised to convey the meaning of the definition: R1, 1.1 Perform a study for each Interconnected Facility to verify that Protection Systems operate in the desired sequence for clearing Faults and remove from service only those Elements required to isolate Faults as follows: 1.1.1 Within 36 calendar months after the effective date of this standard, if no such study for that Interconnected Facility exists that was performed on or subsequent to June 18, 2007 R1, 1.2 Provide to each affected Interconnected Facility owner a summary of the results of each study performed pursuant to Part 1.1 of this requirement, (including, at a minimum, the Protection System(s) reviewed, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each study. R2, 2.2 Calculate the percent deviation between the Fault current values (single line to ground and 3-phase for the bus(s) or Element(s) under consideration) used in the most recent study performed under Part 1.1 of R1 and the Fault current values.... Vpss = Fault current value used in the most recent study R4, 4.1 Within 90 calendar days after receipt, confirm agreement with the summary results of a study as described in Requirement R1, Part 1.2. Conforming changes can be made to the associated Measures and VSLs. 2. We do not agree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. If this is a training requirement, it should be transferred to the appropriate PER standards. c. Measures M1 is removed from the standard. This does not conform with the Elements of a Reliability Standard template, specifically those specified in the “Mandatory and Enforceable Sections of a Standard”. d. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. However, leaving this not measurable and unnecessary requirement in PRC-001-3 is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT could have proposed a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee’s advice/direction for appropriate actions. 3. The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after “where such explicit approval is required” in the Effective Dates Section on P. 2, to the following effect: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.”
Individual
Thad Ness
American Electric Power
No
AEP recommends the removal of the language, “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards”. AEP recommends as an alternative to the removal of the language, modification of the language to reference the TOP standards that should be adhered to in conjunction with PRC-027.
No
No
36 months is not adequate for unique Protection System Studies to be conducted for the TO, GO, and DP. The interface and coordination requirements as written will require close communication with a vast number of interconnected facilities. In addition the generation landscape changes over the next few years with the large number of generation retirements and additions will continually change the short circuit model. AEP feels that these contributing factors will lead to time requirements above the proposed 36 months currently in the standard. AEP would require a minimum of 60 months to

complete this work as the AEP system exists today. An added complication that will impact this time requirement is the approval of FERC Order 1000, which could result in additional interfacing TO's inside AEP's footprint. In addition, NERC's rationale for R1 states that "the SDT has no evidence there is widespread miscoordination between Interconnected Facilities that warrants a shorter time frame." If this is the case, then there should be no issue with extending this timeframe. Using the word "demonstrates" within the definition for Protection System Study could be interpreted as requiring an actual, operational test rather than a simulation study. We recommend changing the definition to "a study that demonstrates that the existing or proposed Protection System design will enables the Protection System to operate in the desired sequence for clearing Faults." Is using the defined term "Protection System" appropriate? Does it possible bring things into scope (CTs, PTs, Station batteries) which should not?
Yes
Yes
No
The 90 Day window will not be sufficient during the initial R1 time frame. AEP suggests 180 days during the R1 compliance window.
No
AEP has suggested adjusting the time requirements, as stated in Question 3 and 7. These time requirements should be included and the VSLs should be scaled accordingly.
We agree with the comment in the background section that the SAR written for this project was focused on System Protection Coordination, and we recommend that PRC-001 R1 should be moved to another standard more focused on operations or training. TOP-006 R3 might be a more appropriate standard for such a requirement. For R1, the standard needs to clearly state the boundaries of the required study(ies). In addition, detail is needed regarding the depth of study away from the point of interconnection, and how far into the generating unit auxiliary system or interconnecting system must be evaluated. Based on the redline provided where R3 and R4 have been removed, and assuming the SDT is not willing to moving the sole remaining requirement to another standard, the title and purpose of resulting PRC-001 would need to be changed. If PRC-001 R1 remains as it is, the phrase "familiar with the purpose and limitations of protection system schemes" needs additional clarity. Doing so might help prevent a CAN from being developed to provide such clarity. AEP suggests the time requirement on R4.3 associated with R3 needs to be extended to 60 days.
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes
We agree with the purpose of the standard. We disagree with the execution of this purpose. This standard only addresses a very narrow reliability issue. Does the SDT really believe that this narrow concern needs all the documentation called for in the standard? At a minimum, a Protection System Study, proof that you checked for a +/- 10% Fault current change regularly, and proof that you have communicated with other registered entities on these issues? And this will be for every interconnection. We feels this is regulatory overkill and not indicative of a results based standard.
No
No
There is no need to have a Protection System Study available for review for every Interconnected Facility. The study is useful only as an intermediate product that leads to relay settings and as a basis for both entities to agree that their planned settings will coordinate. The results based objective is that the registered entities communicate and coordinate together. A simple statement by both entities that they have reviewed each other's settings and agree they coordinate is sufficient proof that the reliability objective of this standard has been met.
No

We do not agree with this requirement. The selection of a +/- 10% threshold is entirely arbitrary. For instance, some entities will set Z1 to 80%, leaving a 20% margin for error. Some entities will set it at 90%. The SDT should allow entities to decide for themselves when a review is needed. As we stated before, the results based objective is to communicate and coordinate. Not to prove whether the fault current at a certain bus is +/- XX% greater than it was at some time in the past. Furthermore, the SDT itself states there is no proof that failure to coordinate protection systems is causing reliability issues. If entities allow their systems to become uncoordinated, we would expect it to come to light as a Misoperation and be handled under PRC-004. We do not agree it is the TO's responsibility to maintain a short circuit model for other entities. What responsibility does the TO take on if it models a generator's short circuit capability incorrectly? This is a very real concern among transmission protection engineers when attempting to model large wind farms with their proprietary models.
Yes
We agree with the list in R3.1. We feel that R2, R3.2 and R3.3 are unnecessary. Instead, the list in R3.1 should act as a trigger requiring both entities to document communication agreeing that coordination exists prior to putting the changes into effect. No communication under R3.3 should be required if the changes restore the system to its original state – replacing a failed relay like for like.
Yes
We agree that the entities should agree prior to any changes being implemented. The only date of interest, in our opinion, is the in-service date of any proposed changes. If agreement is reached prior to the field changes being made, then that is all that matters.
No
No, we do not agree. R4.2 should apply here. R4.1 and R4.3 should be eliminated. If one entity proposes making settings changes, then agreement must be reached prior to implementing the changes. We feel all these timelines are unnecessarily burdensome to remember and quite arbitrary. If one entity feels it cannot get another entity to respond or to reach agreement on coordination, they can always ask their RE for assistance in maintaining the reliability of the system. Since all these activities occurred long before the mandatory standards existed and are covered under the present PRC-001, we do not feel the REs will be swamped with calls if R4.1 and R4.3 are eliminated.
We note that the formulas in R2 use V for current. For clarity's sake, we believe current should be denoted using the letter I.
Group
Southwest Power Pool NERC Reliability Standards Development Team
Jonathan Hayes
No
We would ask that the team revise the second part of the purpose to lead in with "In accordance with the system performance specified within requirements established in other approved NERC Reliability Standards" If left as is it reads like you are required to do both the first and second parts of the purpose. This proposed language requires the initial goal of this standard and references that it will do so under the system performance specified in NERC standards.
No
Yes
Yes
No
In R3 we would suggest that re-rating could be use as a temporary procedure which is addressed in the TOP standards and if the drafting team needs to include these types of re-ratings that they be more specific to exclude the temporary re-ratings. Changes to generator unit(s), including replacements, Output change that causes a change in the protection system, and impedances
No
We agree with the need but feel it needs to be more detailed to include wording that would address

that the coordinated owner has all appropriate data to perform the study before his 30 day timeline begins. We would also like to see a conflict resolution process included under this requirement.
Yes
Yes
In R2 the 24 month time period needs to be changed to 60 months. If fault currents are already being calculated for changes to the system there should be little to no need for a more current check of the fault currents. We feel like the 24 months could be burdensome to smaller entities. We would ask that PRC001-3 be retired and the requirement in it to be moved to a SAR for an existing PER training standard. It also seems incomplete that a standard with a single requirement has no measures. Is there a need for the defined term “Protection System Study” in this standard to also be a new term in the NERC glossary of terms? Is there other wording that could be used in place of this new term since it is only being used as part of this standard?
Group
National Grid USA / Niagara Mohawk
Michael Jones
Yes
No
Yes
As a TO our experience has been that many GOs do not reply to requests for information. If the 36 month window cannot be met by a TO because information requests are ignored what recourse does the TO have to avoid a penalty for non-compliance?
Yes
Please clarify where the fault is to be placed and where the deviation is to be observed. One possibility is to place the fault at a bus at one end of the tie and then determine the devieation in the current in each element connected to said bus.
Yes
Yes
Yes
In the event that someone hands you a study of their entire system or of all their interconnections you should only be responsible for reviewing study results for those interconnections in which you are a participant. Furthermore, what if you don’t agree with the study results you’ve been handed? The text as written literally commands you to agree with them! The text should be reworded to require a response (not necessarily agreement) within 90 days and relative only to the portion of the study applicable to interconnections you participate in.
Yes
1.Regarding the definition of “Interconnected Facilities,” when the functional and operating entities are part of the same corporate entity documented correspondence within that same corporate entity seems of little benefit. In fact, it could be the same individual wearing two hats in the same corporate entity who would have to document communications with him/herself. 2. Example process on page 22 should not automatically make it the responsibility of entity B to propose a solution to a problem discovered by entity A quite possibly resulting from system modifications initiated by entity A. Whether entity A or entity B is in a better position to propose a solution depends entirely on the circumstance and there needs to be flexibility as to who is obliged to come up with a fix. 3. Application Guidelines, Fig. 2 and Fig. 5 require the TO to verify "...the generator Protection Systems..." coordinate with the TO's systems. The scope of generator protection systems should be narrowed to just distance relays and overcurrent relays that look out onto the TO's system. If the

high side winding of the transformer that interconnects to the TO is ungrounded and zero sequence overvoltage protection is provided for the transmission, then that would be appropriate to include in the scope of TO responsibilities too. The expertise in other types of generator protection likely resides with the GO and not the TO so it would be best if the GO handled the coordination of those other types of protection. 4. Application Guidelines, Fig. 3 requires the TO to verify the DP's and the GO's protection systems coordinate with the TO's. Yet the GO doesn't even connect directly to the TO. It should be the DO that checks coordination of the GO with the DP for faults on the transmission side of the DP's substation transformer (assuming the DP has installed transmission protection at the sub) and the TO that checks coordination of the DP's transmission protection with the TO. If all of the transmission protection is back at the GO (in other words the DP has installed no transmission protection at its sub) then to do as this app guide suggests the TO will require an accurate short circuit model of the DP's system between the GO and the TO. Furthermore it would require that the DP keep the TO continuously appraised of changes to the DP's system that impact the short circuit representation. Considering the proliferation of distributed generation being interconnected to distribution systems the burden should be on the DP not on the TO supplying the DP to verify coordination of what could be a multitude of interconnections to the DP. Furthermore, the scope of the text "....generator protection systems...." should be narrowed so a TO or DP is not responsible for the coordination of devices it doesn't even own, maintain or set. When study work is required to interconnect a GO to an entity, the entity is commonly reimbursed by the GO for study work. Yet this app guide requires a TO to perform study work for the benefit of a GO which does not even directly interconnect with it so how will the TO be reimbursed for it's efforts?
Group
Pepco Holdings Inc. & Affiliates
David Thorne
No
1)The language in the Statement of Purpose needs to be reworded. The phrase "remove from service only those elements required to isolate faults" may restrict certain protection practices in widespread use today, where coordination on tapped distribution facilities is achieved via auto-reclosing rather than via coordinated time delays. For example, a BES line (protected by a high speed DCB or POTT pilot scheme) is tapped by a distribution provider as demonstrated in Figure 3 of the Application Guidelines. Very often for distribution taps like these, rather than requiring the distribution provider to establish a costly transmission class pilot scheme terminal at breaker C with communication links to A & B, it is common to let the pilot scheme reach into (but not thru) the transformer at C. For faults in the transformer the high speed transformer relays will operate to trip and lockout breaker C. However, the pilot scheme at A & B will also trip simultaneously. Breaker C will lockout and A & B will auto-reclose to restore the line. Coordination is achieved via auto-reclosing. For faults on the line, A & B will trip via the pilot scheme, and if generation happens to be running either C will trip, or the generator will trip depending on scheme design. Reclosing at A & B would be delayed and / or voltage supervised to ensure generation has been removed prior to auto-reclosing. In the above scenarios since the line tripped for a fault in the transformer, or the generator tripped for a fault on the line, it would violate the requirement to "remove from service only those elements required to isolate faults". The language used in the proposed definition of Protection System Study is slightly better, using the phrase "demonstrates ... Protection Systems operate in the desired sequence for clearing faults". The problem here is who determines what is the "desired sequence"? Would a scheme, which is purposely designed as described above and acknowledged by the Transmission Planner and Transmission Operator, be considered to operate in the "desired sequence" for clearing faults? 2)The language in the standard needs to be re-visited to enable these types of protection interfaces with distribution providers having limited generation resources connected downstream. Also, if system reliability was truly an issue for this example, the interconnection should not have been a simple tap on the line, but rather a ring bus should have been established at the interconnection point.
No
No
Each owner should already possess information demonstrating that their protective devices are set to "coordinate" with adjacent protection systems. However, the documentation that presently exists may not be in the form of a formal "coordination study" in a format suitable for audit purposes. Some

guidance should be provided indicating what form of documentation is expected, especially by the TO. For instance, on transmission tie lines between different TO's coordination of zone distance elements is fairly straightforward and can be accomplished without a traditional "coordination study". Also settings on pilot schemes need to be exchanged in order to allow for proper operation, but this is also not what is considered a traditional "coordination study". On the other hand, coordination between GO's and TO's is even more complicated. Without some direction as to what specific documentation is required it is difficult to estimate how many existing interconnection points would have to be re-visited in order to produce the required auditable documentation. Some specific examples of what specific type of documentation is required would be helpful. To be safe, most likely all interconnection points would be revisited to ensure adequate compliance documentation. Also, for each revised Protection Study produced (per R1.1) a formal review (R1.2) and approval (R4.1) would be required. As such, with the large number of interconnection points on the system a 60 month time frame would be more appropriate. The SDT acknowledged that they had no evidence that there is widespread miscoordination between Interconnected Facilities when establishing the arbitrary 36 month requirement.
No
The 10% threshold would be acceptable providing the following changes were made to Requirements R2.1 and R2.2: R2.1 – Re-word Requirement R2.1 to read: "Perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities, not less than once every 24 months. R2.2 – Re-word Requirement R2.2 to read: "Calculate the percent deviation between the maximum available Fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation..." The existing wording requires one to "calculate the percent deviation between the fault current values ... for the bus(s) or Elements(s) under consideration". Including the phrase "or Element(s) under consideration" increases the complexity of the periodic fault screening requirement significantly. Instead of performing a relatively easy bus fault summary routine (available in most batch short circuit programs) individual branch current in various coordination pairs must be examined. Take for example the system shown in Figure 1 in the Application Guidelines. Instead of just screening the available bus fault current at the point of interconnection (the ownership boundary between the two entities), fault current in each "element under consideration" used in the Protection study must be calculated. This would mean determining fault current flows through breakers A, B, C, D, E, F, G, & H) under various fault scenarios and comparing them to those used in the previous coordination study. This is far from a simple task and not conducive to a "batch" screening tool. The intended purpose of R2.2 is to catch external system changes that have over time led to gradual increases in fault current that may require the Protection System Study to be re-examined. A simple year to year bus fault comparison would serve this purpose. System changes at, or immediately adjacent to, the interconnection point, which could lead to a re-distribution of fault currents through the effected element(s), would be caught elsewhere under R3.1 "Additions, removals, or replacements of transmission Elements".
No
The 10% threshold would be acceptable providing the following changes were made to Requirements R2.1 and R2.2: R2.1 – Re-word Requirement R2.1 to read: "Perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities, not less than once every 24 months. R2.2 – Re-word Requirement R2.2 to read: "Calculate the percent deviation between the maximum available Fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation..." The existing wording requires one to "calculate the percent deviation between the fault current values ... for the bus(s) or Elements(s) under consideration". Including the phrase "or Element(s) under consideration" increases the complexity of the periodic fault screening requirement significantly. Instead of performing a relatively easy bus fault summary routine (available in most batch short circuit programs) individual branch current in various coordination pairs must be examined. Take for example the system shown in Figure 1 in the Application Guidelines. Instead of just screening the available bus fault current at the point of interconnection (the ownership boundary between the two

entities), fault current in each “element under consideration” used in the Protection study must be calculated. This would mean determining fault current flows through breakers A, B, C, D, E, F, G, & H) under various fault scenarios and comparing them to those used in the previous coordination study. This is far from a simple task and not conducive to a “batch” screening tool. The intended purpose of R2.2 is to catch external system changes that have over time led to gradual increases in fault current that may require the Protection System Study to be re-examined. A simple year to year bus fault comparison would serve this purpose. System changes at, or immediately adjacent to, the interconnection point, which could lead to a re-distribution of fault currents through the effected element(s), would be caught elsewhere under R3.1 “Additions, removals, or replacements of transmission Elements”.
No
1)Requirement R4 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What if agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R4.2 until agreement is reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? 2)Requirement R4.3 requires confirmation of agreement within 30 days of being notified of corrections made due to as found setting errors or emergency replacements of Protection System components. Again, what if the changes are not acceptable to the other party? Which entity is found not compliant, the one who proactively made the changes or the one who won’t confirm agreement? This is the problem with mandating that an agreement between two parties be reached. It is further compounded by requiring that an agreement be reached within a set timeframe. 3)It is important to ensure that information on new, or modified, Protection Systems are shared between parties, so that each party may assess the impact of the change and ensure their Protection Systems are properly set and coordinated. The emphasis should be on sharing of information (such as relay setting changes) and not the details of performing the “Protection System Study” and all the associated approval schedules. As such, it may be reasonable to have a Reliability Standard to ensure setting information has been exchanged (which was the original intent of the PRC-001-1 standard). But it should be left at that. Mandating mutual agreement with compliance implications, without providing some outlet for a dispute resolution process seems unfair to either party. As such, we suggest Requirement R4 be removed entirely or extensively re-written to address the concerns outlined above.
No
We suggest Requirement R4 be removed entirely or extensively re-written to address the concerns outlined in our response to Question 6.
No Comments
1)The SDT states that “the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address the appropriate use of time delays in relays”. However, a word search of the 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. 2)The mention of “the appropriate use of time delays in relays” in the 2003 Blackout Report was in the context of the actuating time of relays in response to system overload

conditions, and generator protection to voltage and frequency excursions during stressed system conditions. The concern was that relays operated on overload before system operators could react and that some generators tripped (exacerbating the collapse) before other system schemes (UFLS or UVLS) could operate. 3)The solution was not to increase the time delay on Zone 3 relays (which would have been intolerable for fault clearing purposes) but to address the relay loadability issue in PRC-023, to make them immune from operating under heavy load conditions. Similarly the premature tripping of generators on voltage and frequency protection during stressed system conditions (not fault conditions) and coordination with system UFLS and UVLS schemes was discussed in the report. Likewise those issues have now been addressed, or are being addressed, in PRC-006, PRC-010, PRC-022, PRC-019, and PRC-024. 4)Similarly in the recent Southwest Blackout of 2011 the operation of relay schemes during overload conditions was a contributing factor. There was again no evidence of miscoordination of relay schemes during fault conditions. The unexpected operation of relays and SPS's during overload conditions could have been avoided by proper application of existing standards PRC-023 and PRC-014-0. 4)Based on the above, where is the historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions? Reliability Standards should be adopted based on a need to address a known, or probable, reliability issue. As such, although we support the overall desire to ensure that protective systems are "properly coordinated"; we see little value in developing a new Reliability Standard to address something that is routinely practiced and which has not been demonstrated to be a contributor to major system disturbances, or cascading outages. Even the SDT in their rationale for Requirement R1.1 stated that they have no evidence that there is widespread miscoordination between Interconnected Facilities. In lieu of a formal standard to address relay coordination during faults, a simple technical reference document on Protective System Coordination issues may provide equal benefit to the industry. 5)PRC-001 With the vast majority of the requirements from PRC-001-1 being removed, the Title and Purpose of proposed standard PRC-001-3 no longer seem appropriate for the content remaining therein and should be revised. The only remaining requirement in PRC-001-3 states that "Each Transmission Owner, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. This does not seem to be a Protection System Coordination issue. 7) The definition of Interconnected Facilities should reference Registered Entities rather than functional, operating, or corporate entities. BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities Registered Entities (TOs, GOs, and/or DPs). 8) Is Facility and/or Element the best term(s) to use in the definition? It seems to say Elements that are joined by Elements? If not, should the definition be further revised. NERC Glossary of terms for Element: Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components. NERC Glossary of terms for Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.) 9) Does joint own lines and stations create issues? Should the definition or standard make a distinction between principal owner and financial owners?
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Yes
No
Yes
This seems like an adequate time, but it is unclear that smaller transmission dependent utilities really need to do this to maintain reliability and if their ratepayers would see any reliability benefit.
Yes
No
Comments: R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and

GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward
Yes
Yes
No
Comments: We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in “guidelines and Technical Basis” that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.
Group
Hydro One
Sasa Maljukan
No
The goal of this standard is to address co-ordination of protection systems between neighbouring entities. To achieve this goal, the efforts should focus on the co-ordination of protections between entities as outlined and described in the NERC SPCS paper “Power Plant and Transmission System Protection Co-ordination – Technical Reference Document (TRD),” dated July 2010. This standard should include the review/study of all protections requiring coordination not the ones dealing with faults only as identified in the above TRD. There should be one comprehensive study/report not spread out into 7-8 standards. If so, there are still protection elements that require coordination that have not been addressed such as: open-phase, loss-of-field, over-excitation, out-of-step, and negative sequence normal unbalance, etc. We don’t see how a standard for Protection system co-ordination can rely on other standards to achieve the goal of co-ordinating protections for both Faults and other conditions that challenge co-ordination. The Purpose should be: “To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate from abnormal system conditions, while meeting the system performance specified within requirements established in NERC TPL Reliability Standards.” If the above suggestions are not taken into consideration and the SDT decides to keep the requirements in the current form, the statement“...while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.” should be changed to include exact reference to standards or at least group of standards the SDT is referring to.
Yes
This is related to our comments from Question 1. We believe that the Planning Coordinators (PC) shall be included. PCs are accountable to conduct studies to determine critical clearing times, stable and unstable power swings, etc., to determine coordination. Transmission and Generator Owners do not have access to such information or the tools/experience to conduct such studies. In addition to this there is a possibility that the entity in charge of day-to-day operation of the Interconnection Facilities (likely registered as TOP only) doesn’t own the facility and consequently is not registered as a TO. In this case, such facility or the facilities would be out of scope of this standard. We believe that the SDT should refine the Applicability section to encompass the above mentioned cases. From a reliability point of view, we think that this standard should not be applicable to Distribution Providers because the TO is mostly responsible of coordination of the protection with the DP.
No
Hydro One would like to suggest that 60 months would be a more realistic span of time needed in order to formally complete a documented study, or derive a time frame based on the number of interconnections that an entity must conduct studies for. Whether the systems are co-ordinated or not, the work needs to be carried out and documented. In the case of Hydro One there are almost 300 individual generator connections that belong to other entities many of whom do not have onsite protection experts. Most of these connections do not have a formal documented protection co-ordination study. Statements in R1.1.2 and 1.1.3: “unless the entity can demonstrate such a study is not required.” and its corresponding measure: ” or documentation demonstrating why a study is not required for changes described in Parts 1.1.2 and 1.1.3” are vague and don’t give much guidance on

what would be the appropriate evidence in this case. Suggest adding examples of documents that can be used to demonstrate compliance.
No
Hydro One agrees with the need of a defined fault current threshold. However, we'd like to suggest a 20% threshold instead as most protection settings, if coordinated properly, must coordinate with system normal and under credible minimum system conditions, therefore, it is our opinion that a 10 % change should generally not affect coordination.
No
While we agree with the principle of exchanging information, R3.1 is confusing "...or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities." We believe that this statemant is too inclusive. It implies that changes in facilities other than the Interconnected Facility need to be communicated and is too open for interpretation. Suggest the scope be better defined and limited only to changes at the Interconnected Facility.
Yes
Yes
Yes
1. This standard has been written on the basis that one of the Entities initiates the process and that both, assuming 2 only, conduct their own independent Protection System Studies; and then at the end of the process they agree, etc. Based on our experience, it is more efficient that both parties work in cooperation to conduct the Protection System Study and that they produce one report document which is then approved by both entities as meeting adequate coordination requirements.The Protection System Studies report shall be dated, and include the fault values at the time of assessment and should be filed as compliance evidence. 2. The SDT states "The SDT has no evidence there is widespread miscoordination between Interconnected Facilities...." This is contrary to the NERC TRD that indicated that there was plenty of co-ordination issues during the 2003 Blackout. Suggest removing this statement as it is contradictory and serves no purpose since the documented Protection System study has to take place regardless. 3. We feel the standard would be more useful to the industry if a list of applicable Protection System elements that require co-ordination is presented in the requirements section in line with the NERC white paper. Much like PRC-023 that identifies specific elements and corresponding numbers, we feel this approach would result in proper Protection System studies being undertaken for elements that are affected by this standard. The SDT claims some elements will be covered in other standards so the scope of elements that need co-ordination needs some clarity. 4. PRC-001-3 lists "first day of the first calendar quarter twelve months following" as the Effective Date. However, the implemenation plan states that the effective date is the same as for PRC-027-1 which is "first day of the first calendar quarter that is three months beyond". Please clarify and ensure consistency. 5. Hydro One is questioning the purpose and existence of PRC-001-3 in its current form. It contains only one requirement that is very vague and not measurable. Suggest that the SDT retires that standard as a part of this project 6. To avoid confusion we ask the SDT to establish 1 to 1 correspondence between the requirements and measure. For example R2 measures should be M2 or M2.1, M2.2 rather than M3 and M4.
Individual
Anthony Jablonski
ReliabilityFirst
No
It may be appropriate to trigger a coordination review based on multiple criteria. For instance, perhaps coordination should be verified at the interconnection at least once every 7 years, as well as whenever the available fault current at the point of interconnection changes by more than 10%. There

may be other better indicators when coordination should be checked as well such as a percentage change in system impedances at the interconnecting buses. RFC also questions whether there is a justification for choosing the 10% criteria (rather than say 5%)
No
ReliabiltiyFirst beleives the VRF for Requirement R4 should be High since it requires completion of the coordination activities. Lack of coordination of Protection Systems can result in larger scale outages.
ReliabilityFirst offers the following comments for consideration: 1. Requirements R1, R2 and R4 a. Requirements R1, R2 and R4 do not follow the format of a typical Results Based Standard requirement (i.e. the parent requirement simply states "the entity shall:"). Result Based Standard risk based requirements should be in the following format: "who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome." ReliabilityFirst recommends modifying these three standards to conform to the Results Based Standard format. 2. Requirement R2 a. ReliabilityFirst questions why Transmission Owners only need to perform a short circuit study on Interconnected Facilities and not their internal system Facilities as well (Requirement R2). ReliabilityFirst believes it would be beneficial for Transmission owners to be required to determine present fault current values (and calculate the percent deviation between the Fault current values) for all internal system Facilities. 3. Need for PRC-001-1 Requirement R1 a. ReliabilityFirst believes PRC-001-1 Requirement R1 is ambiguous and believes the intent is covered in the NERC PER-003-1 standard. It will be very hard for an applicable entity to show that they are “familiar” with the purpose and limitations of protection system schemes applied in its area. Since ReliabilityFirst believes R1 does not enhance reliability, ReliabilityFirst recommends retiring PRC-001-1 Requirement R1 consistent with the effective date of the NERC PER-003-1 standard (effective date of 10/01/2012).
Individual
Martin Kaufman
ExxonMobil Research & Engineering
No
No
No
No
No
No
No
No
PRC-001-3 has a single requirement with no associated measure. Any standard requirement whose implementation can address a reliability gap in the Bulk Electric System should possess a quality that can be measured. The SDT should modify PRC-001-3 and provide a measure for Requirement R1 or redact the standard in its entirety.
Group
Luminant
Brenda Hampton
Yes

No
Yes
Yes
No
Luminant agrees with R3.1 and 3.2. Luminant suggests that the language in this requirement be revised so it is clear what is to be provided between the parties.
No
Luminant agrees with the need to reach an agreement on relay coordination based on the specific circumstances in R3.3.1 and R3.3.2. However, the time period to reach agreement of 30 days should be replaced with an agreed upon time schedule by all parties.
No
Luminant recommends that the time frame should be “according to an agreed-upon documented schedule between Transmission Owner, Generation Owner, or Distribution Provider. Luminant would recommend the removal of the 90 day requirement. 90 days may not fit all circumstances. It should be left between the parties to determine the timeline of the project and reaching agreement. This is what should be documented to ensure coordination of activities between the affected parties.
No
Based on the comments on Q6, the VSL would need to be modified. Q7 and 9, the VSLs would change accordingly to accommodate an agreed-upon time frame for acceptable relay coordination and a method for resolving issues surrounding obtaining an acceptable coordination where differences occur.
Comment on Requirement R1.2. The time frame listed may not be adequate under all circumstances or situations. Luminant recommends that the language be changed in this requirement as follows: “… Protection System Study performed pursuant to this requirement (including at a minimum, the Protection System(s) reviewed, any issued identified, and any revisions proposed) shall be in accordance to an agreed-upon schedule with a Transmission Owner, Generation Owner, of Distribution Provider.” The corresponding measures will also need to be modified if this language is accepted.
Group
Progress Energy
Jim Eckelkamp
Yes
Yes
Yes
Yes
Progress Energy request re-evaluation of time for performing Short circuit strudy in R 2.1. Request 36 months which is same time frame in R1.
Individual
Jonathan Meyer

Idaho Power Company
Yes
Yes
Yes, Transmission Operators may own protection systems but not the interconnected element due to cost sharing agreements among Entities, for example. The applicability should be expanded to cover the Entity responsible for operation of the protection system element and interconnection.
No
No, Should a Protection System Study under R1 result in triggering of the other Requirements in the Standard, more time may be needed. An Entity could easily find themselves responding to multiple inquiries from Interconnectors while performing their own Studies. Additional time should be allowed to address the results of the Protection System Studies triggered during this implementation timeframe.
No
No, We are unsure whether a 10% trigger level is appropriate in this context as the location of the fault is not specified in this Requirement. Faults used to properly set a protective relay will be made at multiple locations and with various source conditions. The Requirement should be more specific in order to achieve consistent coordination among entities.
Yes
Yes
Yes
Yes, There appears to be no mechanism in the Requirement addressing if coordination changes are not acceptable. This should be addressed as 90 days could easily be exceeded in this scenario.
Yes
During our review it appears that an Entity will need to maintain an exceedingly large list of contacts for all Interconnected Facilities in order to ensure that the appropriate personnel receive and respond appropriately to Protection System coordination requests as Required by this Standard. With the probability of regular turnover occurring (retirements, transfers, etc.) at Interconnected Facilities, it would be helpful for a master list of Interconnected Facility Contacts for Protection Systems be held by a centralized Entity, such as a Reliability Coordinator, in order for an Entity to meet the timeframes specified and facilitate reliability via compliance with this Standard. This Standard will enforce consistent communication between Entities which is necessary for coordination of Protection Systems. It does not however, guide an Entity to set relays that will ensure proper coordination. Having a separate Entity verify coordination is desirable, but differences in experience, expertise, and analysis tools between Entities will not ensure proper coordination if methods of checking are not also part of the Requirements.
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
No
The SDT proposed Purpose is confusing. IID proposes the following Purpose language: “To coordinate Protection Systems for Interconnected Facilities, such that during faults, those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.”
No
Yes
Yes

Yes
Yes
No
120 calendar days are suggested instead of 90 because verification of Protection System Study needs to be performed before an agreement can be made and it is time consuming.
Yes
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
No
Yes
Yes
Yes
No
Austin Energy (AE) agrees with the need to coordinate Protection System changes; however, AE believes R4.2 is not sufficiently clear. As written, one could interpret it to mean that a Facility owner must obtain consent on the changes listed under R3.1, not just the Protection System changes (such as relay settings). AE does not believe it appropriate to require a Facility owner to gain consent on the actual change to the Facility itself (such as changes to line lengths/conductor size or replacement of transmission system Element(s), generator units or generator step-up transformer). The Guidelines and Technical Basis (p 20 of PRC-027-1 Draft #1) states, "The purpose of this requirement is to assure the effects that planned changes have on Protection Systems at Interconnected Facilities have been considered by all affected entities." AE agrees with this concept and believes the SDT sufficiently covers it through R1.1.3 and R4.1. AE recommends striking R4.2 from the Standard.
No
Austin Energy (AE) believes that 90 days is sufficient for responding to summary results of a Protection System Study, but it is not always sufficient for completing the iterative discussions that often take place to resolve questions and potential concerns. The Guidelines and Technical Basis (p19 of PRC-027-1 Draft #1) states, "R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to confirm agreement with the summary results of a Protection System Study ...; or absent such agreement, propose revisions to achieve acceptable results." AE asks the SDT to include this "absent such agreement" concept in R4.1 and extend the timeline to accommodate such revisions to one that is mutually agreed upon by the impacted parties.
Yes
Austin Energy (AE) agrees with PRC-027-1 in concept and is prepared to change our vote to affirmative once the SDT addresses the items in these comments. In addition to those provided as part of the specific questions, AE provides the following comments for consideration: (1) AE requests the SDT to identify a timeframe for R1.1.3. The Guidelines and Technical Basis (p17 of PRC-027-1 Draft #1) states, "The SDT believes that specifying a single time frame for evaluation of the wide variety of conditions that may be associated with a particular change is not appropriate ..." The

flowchart on page 21 shows a system change that triggers the need for a new study leading to a box that requires the study be performed within six months. Please remove the conflicting information. (2) AE supports a timeframe that requires a Protection System Study in accordance with a mutually agreed-upon schedule that includes confirmation of agreement with summary results (per R4.1) prior to the in-service date of any planned change. AE suggests the SDT identify this timeframe in R1.1.3 and delete R4.2. (3) AE requests that the SDT change the values in the % Deviation formula (R2.2) from VSCS and VPSS to ISCS and IPSS since V is typically used for voltage. AE also requests the SDT change the variable definitions from “fault current value …” to “fault current magnitude …” to clarify that the phase angle is not included.
Group
Bonneville Power Administration
Chris Higgins
No
The purpose of PRC-001-1 was “To ensure system protection is coordinated among operating entities.” With the rewrite of PRC-001 to PRC-027, the standard drafting team has expanded the purpose to specify that only elements required to isolate faults are removed from service and that system performance established in other NERC standards is met. The two additions to the purpose of PRC-027 should be removed for the reasons described below. The statement in the purpose, “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards”, only serves to unnecessarily complicate the purpose statement. BPA recognizes that the NERC standard does not void the requirements of other NERC standards, therefore, there is no need to state in the purpose that other NERC standards must be met. The statement in the purpose, “such that those Protection Systems remove from service only those Elements required to isolate faults”, drastically expands the scope of PRC-027 over PRC-001. With this new purpose, BPA believes this puts NERC in the position of micromanaging how protection systems are applied. Although most protection schemes are intended to remove only the faulted element, it is not necessarily a problem if additional elements are removed, and there might even be reasons to remove additional elements. In some cases it might be significantly less expensive to design a scheme that allows the removal of additional elements. Protection engineers need to have the flexibility to apply protection schemes that meet the requirements of the project at hand. Creating standards with absolute requirements on how protection schemes are applied and set will eliminate the flexibility necessary to implement effective and efficient protection schemes. The Standard Drafting Team (SDT) does not have the ability to foresee all possible protection scenarios, and to create a standard whose purpose is to remove from service only those elements required to isolate faults will create unnecessary expense and difficulty. BPA strongly recommends that the statement “such that those Protection Systems remove from service only those Elements required to isolate faults” be removed from the purpose and that the standard be modified to eliminate this requirement.
No
No
This question assumes that the requirement to perform a protection system study is acceptable, and the question focuses only on the timeframe allowed. In BPA’s opinion, the requirement to have a protection system study is objectionable and cause for disapproval of the standard. Therefore, the timeframe is irrelevant. In addition, the standard fails to make clear just what a protection system study is, either in the definition, the requirements, or the guidelines that follow. BPA believes that R1 is ambiguous and unacceptable.
No
This question assumes that the requirement to perform a mandatory short-circuit study every 24 months is acceptable, and the question focuses only on the percent change of the study results that will require notification. BPA believes that a short-circuit study should not be required and the percent change that triggers notification is irrelevant.
No
BPA believes that it is not practical to list all of the possible changes that could impact the coordination of protection systems. Any such list will likely lead to unnecessary notification in most cases, while failing to recognize unusual situations that could cause miscoordination. BPA is in favor of

a simplified approach where notification is provided to the owner of the remote terminal(s) whenever a change is made to the protection scheme at one terminal.
No
In many cases, one party of the interconnection is simply implementing the protection system changes provided by the other entity. Requiring the agreement of this party implies that the entity understands what is going on and is not a practical use of time and resources.
No
BPA believes that requiring an agreement from all parties could prevent the implementation of emergency changes.
No
BPA believes that in general, the VRFs and VSL's are too high.
Interconnections are no more prone to misoperations than other power system elements. A logical conclusion is that if the requirements of this standard are put in place for interconnected facilities, they should be put in place for all power system elements. The industry is quickly approaching a prescriptive environment in the protective relaying field which attempts to replace experience and judgment with a massive set of rules. These rules will never be able to eliminate miscoordination and misoperations, and the more rules we have, the more time and resources are diverted from dealing with the critical issues that arise. Entities are no longer free to use experience and judgment to decide what work is most important and instead, focus time and energy on the relentless schedule of NERC requirements. The purpose of the original System Protection Coordination Standard, PRC-001, was to ensure that protection systems were coordinated among entities. This should require only a simple exchange of data between entities when new facilities are added or changes are made. BPA implores the SDT to reduce the burden of the proposed standard by simplifying it and returning to the basic original purpose.
Individual
Don Jones
Texas Reliability Entity
No
We support this reliability objective, but feel that it may fall short of fulfilling all of the required Protection System coordination needs, resulting in a gap in the Standards. The major issue that we see in Protection System coordination is with coordination studies conducted WITHIN an individual entity, not between two or more entities. Using the Misoperation data as an indication, for CY2011, out of 202 total Misoperations in the ERCOT region, 46% were due to "Incorrect settings/logic design", however, less than 2% of the Misoperations occurred on Interconnected Facilities between different entities. This suggests the main problem with Protection System coordination is internal to an entity, not between two different entities. This Standard, as well as PRC-001, are somewhat silent as to what internal coordination should be considered "Good Utility Practice", even though there have been instances where internal coordination was not done.
No
Yes
Yes
Using a +/- 10% change is a good threshold, with the understanding that if a change in fault current value of less than 10% results in a need to change relay settings, then Requirement R3.1 will cover the coordination between entities in that case. Additional comment: For R2.1, Does the SDT also want to consider other system studies in addition to short circuit studies (e.g. critical clearing time studies at generation facilities needed for breaker failure coordination, equipment rating studies, or stability studies)?
Yes
Yes

Yes
Yes
In the Severe VSL for R4.3, the word “entity” was left out after “The responsible . . .”
Requirement R1.1.3: While we agree with the SDT rationale that R3 notifications may occur weeks or years prior to the change, we feel that a time frame should be included in this requirement rather than leaving it open-ended. We suggest that the Protection System Study be completed at least 60 calendar days prior to the in-service date for R3.1 and within 30 days after receiving notification for R3.3. If the SDT agrees with this, then an appropriate VSL should also be drafted.
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
No
Yes
Yes
No
It is not clear what this list should include. Should the protection changes on the interconnected facilities only be included? Or should it include the protection changes on the adjacent elements? Also, for the changes of power system elements, should those connected directly to the interconnecting bus be included or it should also include changes beyond that?
Yes
No
This 90 day time frame may be too long, since an agreement is required from the interconnecting parties before the proposed protection changes can be implemented.
Yes
Regarding R1, it is not clear what specifically the Protection System Study should include. - According the application guidelines on page 17, it states: “Data used to determine Fault currents in performing the study”, what data does this refer to? - Also it states that it should include “listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Interconnected Facility, and were reviewed for coordination of protective relays as part of the study”. It is not clear if it should include a list of all the enabled protection elements and their settings of the protection system package or the package only. Should it include the protection system on the interconnected facilities only or on the immediate adjacent elements as well? - The Application guidelines say it should list any issues associated with the relay settings. It is not clear what should be considered as issues. Does a protection mis-coordination occur only under contingencies (such as primary protection element fails) consider an issue? Do backup protection elements have to coordinate with backup protection elements? Regarding R2, it is not clear what fault current value should be used for the short circuit study. Should it be the total fault current of the interconnecting bus? Or should it be the total fault current of the interconnecting bus excluding the contribution from the interconnected facilities?
Individual
Martyn Turner
LCRA Transmission Services Corporation
No
Reword the Purpose to state as follows: “To allow for the coordination of Protection Systems at

Interconnected Facilities to prevent equipment damage while maintaining proper selectivity during Faults." This phrasing is more consistent with NERC Reliability Standard language where adherence with other reliability standards is not explicitly stated.
No
We agree that applicability of the overall standard should be limited to the Transmission Owners, Generator Owners and Distribution Providers; however, requirements for conducting the Protection System Coordination Study should only apply to the Transmission Owners, Generator Owners and Distribution Providers that have ownership of the protective relay portion of the Protection System. Requirement R1 should read as follows: “Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System that owns a Protection System shall:”
Yes
Requirement R1 should read as follows: “Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System shall:” Requirement R1.1.2 should read as follows: Within 6 calendar months after determining or being notified of a change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.
No
A 10% change in fault current is not an appropriate criterion or "trigger" for relay coordination review. It does not meet the standard’s purpose to ensure speed and selectivity requirements associated with protection system coordination. Requirement R2 should read as follows: “For each Interconnected Facility, each Transmission Owner that has ownership of the protective relay portion of the Protection System shall: “ Requirement R2.2: LCRA TSC recommends not including this requirement. Requirement R2.3: Should the SDT decide to include requirement R2.2, then rephrase R2.3 as follows: “Where the calculation performed, pursuant to Requirement R2, Part 2.2, indicates a deviation in Fault current of 10% or greater, notify each non-transmission owner of the Interconnected Facility, at which the 10% or greater deviation applies, within 30 calendar days after identification. As an alternative requirement to R2.2 and R2.3, LCRA TSC recommends the following language to R2.1, 2.2 and 2.3: 2.1. Perform a short circuit study to determine the present Fault current values, not less than annually. 2.2. Pursuant to Requirement R2, Part 2.1, provide summary results to each directly impacted non-Transmission Owner entity at the Interconnected Facility, within 30 calendar days after completion of the short circuit study. 2.3 Delete
No
Requirement R3 should read: Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System shall provide to each directly impacted Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility, the details (e.g., project schedule, protective relaying scheme types and settings) as follows: The first bullet of requirement R3.1 should read: New installation, replacement with different types, or modification of: protective relays or protective function settings that result in a direct impact on protection system coordination to an entity at that Interconnected Facility. The second bullet of requirement R3.1 should read: • Changes to positive or zero sequence line impedance by more than 5 percent
No
Each Transmission Owner, Generator Owner, and Distribution Provider shall: 4.1. Within 90 calendar days after receipt, confirm acceptance with the summary results of a Protection System Coordination Study, as described in Requirement R1, Part 1.2. 4.2. Prior to the in-service date of any planned change at the Interconnected Facility, confirm the affected Interconnected Facility owners accept the Protection System(s) changes, as described in Requirement R3, Part 3.1
Yes
No
Objectives of R2 and R4 are mostly associated with interchange of information and the associated Violation Risk Factor for these two requirements (R2 and R4) should be LOW.
General Comment: First, as industry comments are considered by the SDT, the standard must continue to take into consideration that the fundamental objective of a protection system is to

prevent equipment damage that may occur as a result of a short circuit by ensuring fault isolation. The secondary objective is to maintain the power delivery capability in the rest of the system during a fault. This must not be compromised. Second, setting of protective relays is an art and finding a balance between dependability and security is already a challenge and may be an area of disagreement amongst owners (in some cases entities may end up “agreeing to disagree”). The standard should not take away the protection system owner’s responsibility and right to set its own protection systems by requiring “Approval” from other interconnection entities at the Interconnected Facility. Specific Comments: Title of the proposed standard The title for this standard is misleading since it only applies to locations that contain Interconnected Facilities. LCRA TSC suggests changing the title to “Protection System Coordination for Interconnection Facilities” Terms Protection System Coordination Study: A study that demonstrates existing or proposed Protection Systems maintain proper selectivity while clearing Faults.
Individual
Alice Ireland
Xcel Energy
Yes
No
Yes
The standard does not specify M2 violation reporting responsibility or assignment of violation due to non-responsiveness of the interconnected entity. Clarification needs to be made as to what is considered acceptable evidence that the affected entity received the study results under measure M2. Would a registered mail confirming receipt at an address be considered acceptable evidence; if not what type of document service would be considered acceptable?
Yes
Similar comments on measure M5 as contained in item 3 above on measure M2. This provision should become effective 36 months after the effective date of the standard.
Yes
Yes
Concievably, there could be non-reliability based reasons why an entity might not provide concurrence. An alternate avenue should be considered as allowable, such as the requesting entity working through the RC to obtain response from a non-responsive entity. Similar comments on measure M9 as contained in item 3 above on measure M2. Measure M9 does not account for non-acceptance under R4.3 or R4.1 as restudy or expanded studies may be required and result in a M9 violation.
Yes
1) It appears that clarification is needed in the Application guidelines with respect to the Generator Owners, Distribution Providers and Transmission Owners. If they are the same corporate entity, do the examples indicate as such and would coordination be required as specified? (It is presumed YES but not clear…e.g. GO "R" and TO "S" could be the same corporate entity). Figure 5 implies the letters "R", "S", and "T" refers to different corporate entities since there is a Transmission Owner R and a Transmission Owner S along with a Generator Owner T. If these letters do not indicate different corporate entities, then is it the intention of the SDT that all GO and DP facilities that connect directly to the BES be treated as "Interconnected Facilities"?. 2) Additional clarification in the Application Guide (figure 3) is required as it would imply that proof is required that generation on a tapped substation does not pose a risk to the transmission system. 3) The dates and documentation requirements for this standard will require an equivalently complex system or database for tracking in order to prove compliance. From review of the standard it appears that tracking of ~8 dates and associated supporting documents will be required for each interconnection study. Additional implementation time should be included in the standard for proper processes and tools to be in place

prior to perform study or re-study work. 4)Most study work would be initiated by R3.2 and typically involve multiple data requests for varying items and with associated responses providing the information. If each email request needs a corresponding response, then much time will be required to match emails topic for topic to meet this measure. The result will be multiple of same measure for study work, increasing tracking time for engineering. (i.e. more tracking time and less engineering time per engineering FTE). If the measure is to be based on first request to last response then this would easier to implement. 5) As existing studies will fall under the measures of this document, with no grandfathering, it is likely existing studies will need to be re-evaluated. As a result, consulting services for competent protection engineering services may become limited and may impact the ability in meeting the 36 month requirement. 6) Larger regional studies with interconnection impacts may be the outcome of more localized studies. Such studies could be recommended as a result of R2 of this document or future year models under R3.1. The time-frames specified in this standard may not be sufficient and no exception method is provided for expanded study work. (i.e.-studies beyond what is would be considered typical for an interconnection study).
Individual
Chris Scanlon
Exelon
No
The current Purpose for PRC-027-1 should more clearly and concisely state the purpose of the standard by relating the purpose of the standard to the definition of Protection System Study (the key element of the proposed PRC-027). The statement, “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards”, is likely to be subject to interpretation by registered entities and auditors alike and cause confusion. The specific Standards should be referenced in a footnote, or the reference should be removed. [For the purposes of this comment and the suggested revision, Exelon removed the reference since we believe this is the best option]. Exelon suggests the following revised Purpose "To ensure Protection Systems at Interconnected Facilities operate in the desired sequence to isolate a fault." In our experience, the term “coordinate” (or “coordination”) caused confusion in PRC-001-1 and therefore Exelon proposes that the term be omitted. In PRC-001-1, the term “coordination" was unofficially accepted as either the correspondence or communication between entities (i.e., via email, memo, fax, etc.), or as the time response relationship associated with backup protection elements. Thus, to avoid this confusion and to match to the proposed Protection System Study definition, Exelon removed it from our suggested Purpose statement above. If the SDT believes that the term "coordination" should remain, it should be clearly defined. Given the Protection System Study definition, a suggested definition for coordination would be “operation of Protection Systems in the desired sequence to isolate a fault”.
Yes
Agree, all entities should be included if they are responsible for engineering of protection systems protecting BES elements at Interconnected Facilities.
No
Exelon cannot agree to the time frame proposed without understanding the scope of work involved in the required protection system study. The current definition of Protection System Study (PSS) is not clear enough to avoid confusion. To better define the "study" as referenced in PRC-027-1 and to ensure that applicable entities know what they’re required to do, the definition of PSS needs to clarify the elements of the protection system and power system conditions the study is run similar to how required Transmission Planning studies are defined. With this in mind, Exelon suggests the following definition for "Protection System Study": A study that demonstrates that existing or proposed Protection Systems operate in the desired sequence for clearing a fault. The study is conducted with a single power system element out of service and all Protection System elements in service, and with all power system elements in service and a failure of a single protective relay, communication system, ac current input, ac voltage input, or DC control circuit (these can be further defined using the information and Table from Order 754). Exelon suggests that “summary results of a protection system study” should also be defined with clear parameters established. Unless the specific particulars are established, Exelon predicts that there will be confusion as auditors attempt to decide whether or not a piece of evidence will qualify as a “summary” of a Protection System Study. This is similar to the ambiguity in the existing revision of PRC-005-1 R1.2 which requires a “summary” of maintenance and testing procedures, yet does not describe specifically what is required. It is our

expierence that registered entities and auditors historically have had differences of opinion about what constitutes a “summary”.
No
Exelon requests that the conditions under which the required short circuit (SC) study are to be performed should be defined. What future reinforcements should be assumed in the SC model, since the result will depend on these assumptions? In R2, 10% or greater deviation in Fault Current may not be adequate to perform Short Circuit (SC) Study. It should be clearly stated what threshold is adequate to perform SC study successfully, and the SDT should provide some examples how the ‘six-month” time frame is considered a “reasonable amount “of time to perform the SC study.
No
In the current draft of PRC-027-1, Requirement 3.1 mandates that for any of the listed network changes, entities must communicate “the details”, (i.e., design information to all entities that share the interconnection). Of the network changes/additions listed in the draft, however, some may result in little or no changes to existing protection system coordination settings, thereby having no impact to Protection Systems of other entities. For example, consider a project by a TO to replace a BES circuit breaker at an Interconnected Facility. Assume that breaker failure protection for that circuit breaker will also be upgraded, but that the settings and all protection functions for the new relay remains unchanged from the old system. According to the language of Requirement 3.1, the TO would be required to transmit design information to other entities associated with the interconnected facility even though the project would have no impact to the other entities. This represents one example of a frequently performed project in which design information is not presently shared between entities at an Interconnected Facility. Mandatory compliance with this requirement, as written, could represent a significant burden to the industry by requiring unnecessary communication of design details to other entities, in addition to the added compliance documentation activity, and having no impact to protection systems of the recipients. Exelon suggests that the SDT clarify Requirement 3.1 such that that if a change to an Interconnected Facility is not expected to result in a change to the desired sequence of Protection System operations , the compliance activities required by R3.1 should be waived
Yes
Comments: Although not stated explicitly, this question seems to be asking about R4, Part R4.2. Exelon agrees that concurrence should be reached prior to the in service date for Protection System changes that result from the equipment changes at an Interconnected Facility as described in R3, Part3.1.
No
This question differs from what is required in the language in the draft standard. In Requirement R4.1, the 90 days allowed is for entities to “confirm agreement” with the summary. If an entity must only respond at the end of 90 days, the response could be that they disagree. In this case, discrepancies must be resolved at the cost of more time. Regardless, allowing 90 days for an entity to respond before an entity can proceed with design could cause serious delays to engineering and design processes. However, until we know what is required by a Protection System study, Exelon cannot offer a suggestion for a suitable timeframe for R4.1. SDT should specifically justify the proposed 90-day time frame. Since, a 90-day time frame may not be sufficient to compile all the required design data and results for Protection System Study (PSS) and to verify the Protection Systems are coordinated within the applicable entities.
Yes
None
Individual
Chris Mattson
Tacoma Power
Yes
No

Yes
Yes
No
1. This list does not appear to sufficiently address BES transformers (e.g., autotransformers). 2. There is concern that R3.1 may introduce either an administrative burden to identify and track every change, including those that would not reasonably impact Protection System coordination, or compliance jeopardy if those changes are not identified and tracked. a. For example, the second bullet under R3.1 refers to changes to line spacing. Assume that, during restoration following a Fault, a damaged insulator on one pole or tower is replaced with an insulator one inch longer. Technically, this changes the line spacing. It is doubtful that the SDT intended that this or a similar but less trivial scenario would trigger a Protection System Study; however, the language may introduce compliance jeopardy. Perhaps a similar metric as used in R2.3 could be applied to the second, third, fourth, and fifth bullets. For example, perhaps a 5% change in interconnecting Element impedance from a baseline could trigger a Protection System Study; this approach could be used in lieu of the second and fifth bullets. It seems that R2.3 would address the third and fourth bullets if the short circuit study were conducted before the change was implemented. b. Additionally, the language in the first bullet under R3.1 may introduce compliance jeopardy. For instance, it is possible for an entity to adjust a current and/or voltage transformer ratio and compensate with one or more relay settings such that the primary settings do not change. In many of these cases, there will be no impact on Protection System coordination. While active communication among entities is advised, the potential for fines in this type of scenario does not seem to be appropriate. The emphasis on the first bullet under R3.1 should be on Protection System scheme (e.g., distance, overcurrent, DCB, POTT, differential), primary settings (including time delays), independence/redundancy, and technology (primarily for communications systems).
Yes
Yes
Yes
Is it the expectation of the SDT that Protection System coordination issues may be identified when Protection System Studies are performed pursuant to R1.1.1? If such issues are identified, is it the intention of the SDT that these issues would constitute violations of PRC-027-1, provided that the process described in PRC-027-1 for remedying these issues is followed? Transmision Owners depend on each other for accurate short circuit models. As proposed, PRC-027-1 does not appear to clearly address sharing of short circuit modeling information among Transmission Owners when incremental changes are made within a Transmission Owner's system. For example, incremental changes in adjacent Transmission Owners' systems may result in a 5% change in Fault current at an Interconnected Facility when the changes are considered separately, but when the changes are considered together, the Fault current might change by 10%. While the +/- 10 % change in an Interconnected Facility's Fault current value as a trigger appears to be reasonable, the proposed standard offers no guidance or requirements concerning the accuracy of an entity's short circuit model or the methods used to determine Element impedances. This issue is most pronounced for zero-sequence impedance, and to a lesser extent negative-sequence impedance, since these parameters are used infrequently in system planning studies. It seems that some standardized approach for determining impedance parameters may need to be developed, whether in this standard or in another standard, provided that some latitude is afforded entities based upon sound engineering judgment. In R2.2, why is it not sufficient to simply include the following in the parentheses: "single line to ground and 3-phase for the bus(s) under consideration"? "The formulas in R2 use V for current. For clarity's sake, current should be denoted using the letter I." Under R3.2, if all applicable entities agree to a schedule, was it the intention of the SDT that the agreed-upon schedule could be longer than 30 calendar days? M8 requires that an entity have evidence that other entities received information pursuant to R3.3.1 and R3.3.2. What if, despite due diligence, one or more entities do not acknowledge receipt? Since notification pursuant to R3.3 is after the fact, to be compliant, an entity

depends upon one or more other entities to acknowledge receipt, but there does not appear to be a regulatory requirement for them to acknowledge receipt in a timely manner, only a requirement to confirm that the changes are acceptable within 30 days of receipt pursuant to R4.3. Consequently, if Entity A notifies Entity B of changes pursuant to R3.3 in 15 calendar days, Entity B would have until 45 calendar days following the change to respond. However, by this time, Entity A might not have documentation that it met its requirements under R3.3. Another challenge with R3.3 and R4.3 is that the language seems to assume that both entities will agree to the changes. While this should usually be the case, there may be instances in which the entity receiving notice may not find the changes acceptable. Additionally, the language in R4.3 may influence the entity receiving the notice to deem the changes as being acceptable, even if they are not, in order to meet the 30 calendar day timeframe. Tacoma Power thanks the SDT for including Figure 4 in the Application Guidelines. In Figure 5 of the Application Guidelines, why would it be necessary to check for coordination issues with Protection System settings associated with Breakers A, B, C, and D? Is this language intended to address reverse elements that are independent of communications systems? Is it intended to include bus differential, which would be the scheme commonly applied? Or, is there some other reason? To what extent can this standard be enforced within a Transmission Owner's system? For example, in Figure 1 of the Application Guidelines, in addition to verifying that there are no coordination issues between Protection System settings associated with Breaker A and, say, Breaker F, does the SDT intend that this standard could be construed to grant regulatory authority to audit that a Protection System Study was completed to verify that there are no coordination issues between Protection System settings associated with Breaker F and other breakers within Transmission Owner S's system? While Protection System settings associated with Breakers A and F may be coordinated, Breaker F may not be coordinated with other Protection System settings within Transmission Owner S's system such that Protection System settings associated with Breaker A might also not be coordinated for some Faults within Transmission Owner S's system. It is believed that this type of situation should be rare and that the scope of this proposed standard should be limited to audit and enforcement of Protection Systems at the Interconnected Facilities, as depicted in Figures 1, 2, 3, and 5. Assume that there is documentation supporting coordination of Protection Systems at Interconnected Facilities. However, during a Fault, a Mis-operation occurs, and the cause of the Mis-operation is attributed to mis-coordination, despite good faith on the part of the entities to coordinate Protection Systems. Is it the intention of the SDT that this Mis-operation would be construed as a violation of PRC-027-1? For example, although they are generally addressed to some degree in Protection System Studies, but often implicitly through margins, factors of safety, etc., phenomena such as CT saturation or DC offset are not always directly analyzed in Protection System Studies and could lead to mis-coordination even if Protection System settings appear to be coordinated in documentation. It is not clear what responsibility the TO has if it models a generator's short circuit capability incorrectly. The proposed changes to PRC-001 (proposed version 3) are supported. As a reminder to the SDT, Protection System design and application is part science and part art, and it may be difficult to thoroughly audit and enforce the latter. Tacoma Power appreciates the opportunity to comment on the proposed standard and thanks you for your consideration of our comments.
Individual
David Gordon
Massachusetts Municipal Wholesale Electric Company
No
MMWEC endorses the comments submitted by NPCC.
MMWEC endorses the comments submitted by NPCC.
Individual
Bill Middaugh

Tri-State G & T
Yes
No
We agree with this description and the entities, however the standard’s applicability is not written as described in the question. We think that “that require coordination for isolating generation and Transmission Faults” should be added to Section 4.2, Facility Applicability.
Yes
Yes
Yes
No
We believe that there are many instances of changes that can made to Protection Systems as required in Requirement 3, Part 3.1 that don’t require coordination between entities but that might be interpreted that the change “modifies the conditions used in the coordination of Protection Systems.” Examples are load encroachment settings, communication port settings, etc. We think language needs to be added with regard to “… modifications that impact the coordination of Protection Systems between entities, of: …” in the first bullet, if confirmation from the other entity is required.
No
We think 60 days is more appropriate. For the receiving party, 30 days may be too short, and for the sending party 90 days may be too long.
Yes
We think there needs to be a time frame associated with the calculation of the percent deviation after the fault duties are calculated. One way to accomplish that would be to eliminate 2.1 and add a 24 month requirement to 2.2., which would require the performance of a short circuit study anyway.
Individual
John Seelke
Public Service Enterprise Group
Yes
Yes
Within RTOs and ISOs, entities such as PJM and NYISO perform such evaluations as part of their transmission planning process. See PJM Manual 14-B, Appendix G, section G.7 which states: “PJM performs short circuit analysis as part of the annual Regional Transmission Expansion Plan (RTEP) baseline assessment. This analysis includes a study of the entire PJM system based on its current configuration and equipment.” Therefore, Transmission Planners should be considered as an applicable entity for R2 as discussed in #9 below
Yes
We do not believe this requirement has been justified for the several reasons listed below. In addition, the “Protection System Study” definition is too vague as to what it should include. We suggest a separate appendix that lists the items that this study should address. We also suggest that the SDT develop several baseline and change case Protection System Study examples, using a common format. These should be incorporated into an appendix within the standard. a. The format and overall purpose of the baseline study has not been provided. It is highly unlikely that a sufficient Protection System Study has been completed or is available for a majority of the Interconnected Facilities since 6/18/2007 within North America. This is due in part to either no modifications being performed at these facilities or lack of data retention (a study was performed but since it was not a requirement, documentation is not available). To require entities to now perform such studies would be a sizeable undertaking and create a tremendous burden to all entities with little benefit to the entities and the reliability of the BES. For older Interconnected Facilities where no changes have been

made in several decades, no benefit to the facility or the BES would come from perform such a study. b. The only time a Protection System Study should be performed is when a driver is in place that will require a possible relay setting changes. These drivers should be spelled out specifically. For example, if there is substation project work that requires relay setting changes, if the relays are being replaced, if a “tie line” is being re-conductored, etc. The requirement to perform a study should also apply to those “interface” relaying schemes that would normally require periodic review. The requirement for a periodic review will be driven by something other than a system configuration change. This may include schemes that have current operated relaying where the setting of the relay is dependent of fault current level. c. The complexity of such a study is uncertain. In most cases, the “interface” relaying between two TO’s or a TO and a GO is very straightforward. In the case of the “interface” between a TO and a GO, the relaying may simply be a transformer differential scheme. In the case of a tie line between two TOs, if the relaying is strictly impedance based, then there is no need to perform a baseline study. In other cases, the study may be more complex. The study may also have to incorporate Protection System devices beyond the Interconnected Facility (e.g. BOP protection for generators, adjacent line or bus protection for transmission facilities). This would increase the amount of time and complexity required to perform the study. How would the SDT define the appropriate protection coordination boundaries for an Interconnected Facility?
No
We disagree with this requirement for several reasons. a. A change in short circuit Fault current, in many cases, does not require relays to be reset. The requirement to perform a Protection System Study for this reason alone will likely provide no benefit when the relay performance is not dependent on short circuit current level. If the relay performance is directly dependent on short circuit level, then a % change in short circuit level may be appropriate. This distinction should be spelled out in R2. b. It is common for relays to be set at 30-50% of the Fault current or 150%-200% of the full load current. A change of +/- 10% in Fault current would have little to no impact on the existing settings and coordination.
No
a. R3 should be rewritten as follows: “Each Transmission Owner, Generator Owner, and Distribution Provider shall provide the following to each Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility:” b. Part 3.1 should be modified as follows: “For any change or additions listed below, provide a project schedule and the reason for the project, whether to an existing or new Interconnected Facility or to other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities:” c. Part 3.2 does not read well and is not supported by the explanation in the text box. It references 1.1.1, 1.1.2, and 1.1.3, but none of these parts allow an Interconnection Facility owner to request information from another owner to perform the Protection System Study. We can understand why Interconnection Facility owners need to cooperate in the performance of such studies. This thought belongs in R1. We suggest a new 1.2 (with the existing 1.2 renumbered to 1.3) as follows: “Each Interconnected Facility owner shall provide data requested by another owner and which is needed to perform the study in 1.1, either in accordance with an agreed-upon schedule, or within 90 days of receiving the request.” We believe 30 days is too short to require a response.
a. In R4 overall, we concur that agreement does need to be reached before changes can be implemented; however, if there is a disagreement that cannot be resolved by the parties within the time frames specified, a dispute resolution process should be invoked. Otherwise, if an owner disagrees with another owner’s results, it has no option but to agree or face a violation of the standard for failing to do so. b. The specific requirement in the question is in part 4.2, not R4. The list of items in R3.1 appeared reasonable. But R4.2 requires agreement to be reached “prior to the in-service date” under R4.2. Allowing agreement to be reached prior to the in-service date could allow one party to unreasonably hold up the schedule. It should be stated as follows: “Within 90 days after receiving the planned changes at the Interconnection Facility, the affected Interconnection Facility owners shall either agree with the changes, or propose alternative changes, stating why such changes are desirable. Failure to provide a response will constitute agreement with the planned changes by the non-responding Interconnecting Facility owner.”
See our response to #6 above, paragraph a.
Did not evaluate.
We have the following additional comments: a. FORMATTING: Remove the bullets in 3.1 and replace

with subparts 3.1.1, 3.1.2, etc. b. With regard to R2, we suggest that the Transmission Planner be required to perform the studies described therein, not the TO. Furthermore, there should be a requirement similar to that suggested in our response to #5, paragraph c, that each TP provide data needed by another TP needed to perform the required study. It should also address how potentially different results for the same Interconnected Facility by the several TPs should be dealt with.
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
Yes
No
I disagree with the requirement for a protection system study. From the draft standard: "The SDT has no evidence there is widespread miscoordination between Interconnected Facilities". There are approximately 18,000 generators in the US. Requiring each to perform a system study would result in costs running into the hundreds of millions of dollars. This will result in lower BES reliability as entities transfer funds from other reliability efforts to comply with this standard.
No
No
The phrase "Changes to generator unit(s), including replacements, re-ratings, and impedances" is too vague. Audit teams could read any change as a trigger. Suggested change: "following the replacement or re-rating of a generator, or following any change to a generator which results in a change in impedance".
Yes
No
Smaller entities do not have the staff resources to respond, and must bid, contract, and receive a report. Further, they must also go through a process to allocate the funds. 180 days at a minimum, but ideally a longer period should be in place to allow for the budget process.
No
There is no generator size limit set for this standard. It should exclude generators below a threshold value. Suggest generators with an aggregate nameplate value below 500 MVA connecting through a single step-up transformer.
Individual
Kirit Shah
Ameren
No
We recommend that the SDT delete the last part of the purpose “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet ‘the system performance specified within requirements established in other approved NERC Reliability Standards’ and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003 R1.3.7 already requires the entity to “demonstrate that System performance meets its Table 1 for Category C contingencies” (TPL-001, -002 also have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1.
No

Yes
Yes
(1) In R2 2.1 we request the SDT add "under normal conditions" or "under maximum system conditions" so that it states "Perform a short circuit study to determine the present Fault current values under normal conditions, not less than once every 24 months. " (2) We request the SDT clarify which Interconnection Facility fault current values are to be compared. If the intent is to keep this general so the entities have the flexibility to compare those fault current values that the entities judge appropriate, please state. Otherwise we suggest adding "Specifically find fault current values flowing into each terminal of the Interconnected Facility for independently applied single line to ground and 3-phase short circuits at its other terminal(s)." (3) We request the SDT change R2 2.2 wording to "Calculate the percent [delete – deviation] change between the Fault current values (single line to ground and 3-phase [delete - for the bus(s) or Element(s)] flowing into each terminal of the Interconnected Facility under consideration) used in the most recent Protection System Study…". This along with our recommended change to R2 2.1 clarifies the short circuit values that are to be compared. (4) We request the SDT change R2 2.1 to "not less than once every 5 years" for consistency with TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. Our experience is that PRC-027-1 R3 will trigger almost all Protection System Studies anyhow.
No
We recommend the following changes to Requirement 3- (1) Include 'static wire' in the second bullet, or more simply state as 'line impedance changes.' (2) Include 'bus arrangement changes' in the third bullet. (3) Change the fourth bullet to include 'Additions, retirements, or changes…' to strive for consistency for generation and transmission.
Yes
Yes
No
We recommend to the SDT that a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale this urgency is not warranted. Most entities will have numerous Interconnection Facilities so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: (a) Lower VSL should be 30 days late. (b) Moderate VSL should be more than 30 days, less than a year. (c) High VSL should be more than a year but done. (d) Severe VSL should be more than a year and not done.
(1) We support and agree with the SERC Protection & Control Subcommittee comments. (2) We commend the SDT on their high quality initial draft of PRC-027-1. (3) We recommend that the SDT delete 'operating' from the Interconnected Facilities definition because their different functional or corporate entities sufficiently capture all of them. We also suggest defining the singular Interconnection Facility, rather than the plural. (4) The SDT needs to improve the application guidance examples by stating what constitutes the Interconnection Facility. The first example clearly enumerates the short circuit locations and values to be compared between the most recent Protection Study and the R2 2.1 value. (5) Application Guidelines Example / Figure 3: The Note should be clarified, or the example should be removed. In terms of regulatory requirements, Breaker-A and B should coordinate with Breaker-C. However, Breaker-C and the Generator relaying does not need to coordinate with Breakers at Station-1 or Station-2 unless the generator meets the requirements of a BES element (75MW or greater). For small generators, protection on the generator to detect faults on the transmission system is for generation protection, not BES protection; as the fault currents would be too small to cause damage to the Transmission System. Generator protection is already covered in Example / Figure #2. (6) Please restate Effective Date more clearly, we suggest "PRC-027-1 shall become effective on the first day of the first calendar quarter [delete-that is] three months following [delete-beyond the date that this standard is approved by] applicable regulatory approvals [delete-authorities],…" to be consistent with the wording of other standards (e.g. PRC-005-2.) (7) Since short

circuit data base models are required to perform the Protection System Study, NERC regions should have a consistent schedule for revising models. Please encourage regions to synchronize their regional modeling calendars to enable entities to have consistent models, especially near region borders, for efficient execution of PRC-027-1 (8) we recommend that the SDT add proposed NERC Standard TPL-001-2 to your list on page 5 regarding the Other Aspects of coordination. It requires short circuit studies in R2.8 for the purpose of determining if the short circuit interrupting requirements are within the interrupting capabilities of circuit breakers. (9) We strongly recommend that the SDT use the term ‘change’ rather than ‘deviation’ throughout for consistency and because the latter term is defined as being different from the norm. The new fault current value is now the norm, not abnormal or statistically different. R1 – 1.1.2 and 1.1.3 use ‘change’, but ‘deviation’ is then used about a dozen times thereafter in the document. (10) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. (a) The overall process would be less burdensome by changing the R2 2.1 to “not less than once every 5 calendar years” which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3. (b) The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. (c) Omitting ‘project schedule’ from R3 would streamline data exchange. (d) R3-3.1 and 3.3.1 should only be required IF the changes effect the tripping or coordinated functions. Digital relays include numerous settings besides these functions; and these other settings should not trigger a data exchange or study. (e) Streamline the process by measuring dates an entity sends information and receives final agreement. It is burdensome for the sending entity to also track and retain evidence showing another entity received information. Specifically change M2, M5, M6, M7, and M8 to measure the date sent. The other entity’s agreement in M9 shows that the overall process met overall time requirements and that the entities coordinated. If an entity demonstrates such a study is not required in R1, M1 should require the other entity to agree. (f) The application guidelines are generally clear and certainly clarify responsibility. We recommend somehow including their methodology in the requirements because it streamlines the exchanged data and clarifies the process in this complex and potentially voluminous undertaking.
Group
FirstEnergy
Sam Ciccone
No
We do not believe the phrase "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" is needed and may be confusing to the reader.
No
However, it should be clear the the DP facilities in scope are only those associated with potentially impacting a BES facility.
No
Requirement 1, Part 1.1.1 – Although we agree with the timeframe, the phrase “within 36 calendar months after the effective date . . . . subsequent to June 18, 2007” should not be listed as a requirement but rather as part of the Implementation Plan.
Yes
No
Requirement 3, Part 3.1 - We believe that some entities registered as both a TO and a GO may face Standards of Conduct issues if a TO is required to provided the “bulleted” data specified within the Part 3.1.
No answer or comment at this time.
No answer or comment at this time.
No answer or comment at this time.
FE offers the following additional comments: ♣ PRC-001-2 R1 – This requirement is vague and causes

difficulties in consisten interpretations between entities and auditors. We ask the drafting team to revise the wording to clarify the expectations, such as including the types of protections system limitations they should be aware of. Enhancements to this requirement were also suggested in the “NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination” which is attached to the SAR of this project. In their assessment of R1 of PRC-001, the SPCTF said “This requirement is a statement of a highly laudable goal, but this is not specific and enforceable. .. It may be possible to restate this requirement in such a way to be measurable and enforceable. The protective system equipment owners (Transmission Owners, Generator Owners, and Distribution Providers) should be responsible to provide the necessary information to the Transmission Operator and Generator Operator to facilitate their familiarity with the relevant protective systems.” We ask the SDT to review this assessment and make changes to PRC-001 and PRC-027 to assure the reliability goal of PRC-001 R1 is met. ♣ With the approval of PRC-027-1, Requirements R3 and R4 will be retired from PRC-001-1 (Requirements R2 & R3 from PRC-001-2, approved as part of the Real-time Operations Project 2007-03) PRC-001-3 will have the same effective date as PRC-027-1. However, in the redlined version of PRC-001-3, the effective date is designated as “the first day of the calendar quarter twelve months following applicable regulatory approval”. This is not what is specified in the Implementation Plan.
Group
Southern Company
Antonio Grayson
No
Reference the ‘required to isolate Faults ‘. In some cases the design of the protection system may take more Elements out than the faulted element, such as a transformer differential that trips a transmission bus and then opens a HS Bank disconnect. For this reason we would prefer the term ‘as designed’ be used. We feel that it is important to identify the Protection Systems that are to be evaluated; perhaps a clear reference to the NERC Technical reference document?
No
No
60 months would be more reasonable for those that have a large number of generators and/or interconnections. Perhaps a tiered approach: 36 months for those with less than 50, 60 months for those with more than 50 but must have 50% done within 36 months?
Yes
When calculating the “+/- 10 % Fault current threshold”, the use of bus fault values vs the line contribution values should be clarified.
No
Reference the bullet on Line items; the issue of mutual coupling and/or overhead grd wire replacement or changes should be included. Perhaps change to any change that impacts the positive, or zero sequence impedance.
No
If there is a requirement to agree, what happens if there is no agreement. There must be a resolution process.
No
Within “90 calendar days after receipt, confirm agreement” vs “90 day time frame for responding to a request”. Acknowledgement of the receipt and review of a change should be the limit here - agreement with the settings should not be required.
1. The separation of PRC-001-1 in three directions is appreciated. This move was a move in the right direction in our opinion. 2. Whereas the SPCTF may believe that the existing PRC-001-1 was too vague and was not measureable, we believe that the initial draft of PRC-027-1 is overly specificative. Contained within the four listed requirements are actually 11 requirements with 11 different time critical counters that are not to be violated. It is our opinion that equally effective reliability improvement results can be achieved with a standard that is of the form of something in between these two extremes. We propose to eliminate the multiple calendar based time framed requirements

and simplify the eleven requirements into four simply stated requirements. The four requirements, simply, could be: 1) For each Interconnect Facility (IF), perform a Protection System coordination study/review every X years or sooner if triggered by Y. (Y = available fault current change % [r-iii below], system configuration change or other protection system change [r-ii below]); 2) IF owners must notify other IF owners of changes that may affect the other IF owner's Protection System coordination study. (list items likely to affect coordination-this list includes everything in the draft standard R3); 3) TOs are to notify other IF owners if available fault current changes significantly %; 4) IF owners must share & acknowledge receipt and review of their IF Protection System coordination study with other IF owners of that IF. 3. On figure 5 (p. 27 of the draft standard), it seems unreasonable to require that the GO coordinate their protection with that associated for breakers E, F, and G, which are three breakers away from the generator. 4. There is an error on p 5 of the Technical Justification document under Requirement R3. In the first sentence, it is R1, not R3, that requires the IF owners to evaluate the impact to their Protection Systems due to proposed changes by others.
Group
Santee Cooper
Terry L. Blackwell
No
It would probably be good to avoid using the term “coordination” as it can be considered as having two meanings, either the “coordinating” of the exchange of the data or the “coordinating” of the actual protective devices. Coordination should be taken out of the title and the purpose. “To Coordinate Protection Systems” could be changed to “To communicate and exchange Protective System data…” in the Purpose. The title could be changed to “Protection System Interconnected Facility Performance during faults”
No
Yes
Yes
No
In R3, 3.3.1, change the wording to address “changes” instead of “corrections” for “errors.” Many changes are made that are not the result of errors. The purpose here should be to communicate changes, and people shouldn’t have to debate whether or not to make an “improvement” (not because of an error or misoperation) because it may be construed as a correction of an error.
Yes
Yes
No
The 10 day VSLs are too restrictive in R1.1.1. VSL times should be similar for all requirements. Suggest dates should be as follows: Lower – 30 days late, Moderate – more than 30 days, less than a year, High – more than a year, but completed, Severe – more than a year or not done.
The documenting, notification and replies required in this standard will put a significant strain on the time of settings personnel. While we agree that this coordination of data is very important, any simplification of the processes would help ensure that protection system staff has the time to do other critical protective system work, in addition to interconnection studies. Possible suggestions would be change R2 2.1 to a longer time period, since most re-coordinations are due to changes covered in R3. “Not less than once every third year,” would fall in well with the audit schedule. Not less than once every fifth year would match TPL-001-2 draft 5. Also, you could conceivably not have R3 3.3, since those are covered by the statements in 3.1 and 3.2
Individual
John D. Martinsen
Public Utility District No. 1 of Snohomish County

Yes
Comments: SNPD agree with the purpose of the standard; however we disagree with the execution of this purpose. This standard only addresses a very narrow reliability issue. Does the SDT believe this narrow concern needs all the documentation called for in the standard? At a minimum, a Protection System Study, proof that you checked for a +/- 10% Fault current change regularly, and proof that you have communicated with other registered entities on these issues? And this will be for every interconnection. We feels this is regulatory overkill and not indicative of a results based standard.
No
No
Comments: There is no need to have a Protection System Study available for review for every Interconnected Facility. The study is useful only as an intermediate product that leads to relay settings and as a basis for both entities to agree that their planned settings will coordinate. The results based objective is that the registered entities communicate and coordinate together. A simple statement by both entities that they have reviewed each other's settings and agree they coordinate is sufficient proof that the reliability objective of this standard has been met.
No
Comments: SNPD does not agree with this requirement. The selection of a +/- 10% threshold is entirely arbitrary. For instance, some entities will set Z1 to 80%, leaving a 20% margin for error. Some entities will set it at 90%. The SDT should allow entities to decide for themselves when a review is needed. As we stated before, the results based objective is to communicate and coordinate. Not to prove whether the fault current at a certain bus is +/- XX% greater than it was at some time in the past. Furthermore, the SDT itself states there is no proof that failure to coordinate protection systems is causing reliability issues. If entities allow their systems to become uncoordinated, we would expect it to come to light as a Misoperation and be handled under PRC-004. We do not agree it is the TO's responsibility to maintain a short circuit model for other entities. What responsibility does the TO take on if it models a generator's short circuit capability incorrectly? This is a very real concern among transmission protection engineers when attempting to model large wind farms with their proprietary models.
Yes
Comments: SNPD agrees with the list in R3.1. We feel that R2, R3.2 and R3.3 are unnecessary. Instead, the list in R3.1 should act as a trigger requiring both entities to document communication agreeing that coordination exists prior to putting the changes into effect. No communication under R3.3 should be required if the changes restore the system to its original state – replacing a failed relay like for like.
Comments: SNPD agrees that the entities should agree prior to any changes being implemented. The only date of interest, in our opinion, is the in-service date of any proposed changes. If agreement is reached prior to the field changes being made, then that is all that matters.
No
Comments: SNPD does not agree. R4.2 should apply here. R4.1 and R4.3 should be eliminated. If one entity proposes making settings changes, then agreement must be reached prior to implementing the changes. We feel all these timelines are unnecessarily burdensome to remember and quite arbitrary. If one entity feels it cannot get another entity to respond or to reach agreement on coordination, they can always ask their RE for assistance in maintaining the reliability of the system. Since all these activities occurred long before the mandatory standards existed and are covered under the present PRC-001, we do not feel the REs will be swamped with calls if R4.1 and R4.3 are eliminated.
We note that the formulas in R2 use V for current. For clarity's sake, we believe current should be denoted using the letter I
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP, (Occidental Chemical Corporation)
Yes
Ingleside Cogeneration LP agrees that PRC-027-1 should be tightly focused on Fault isolation only.

There are other PRC standards which govern the coordination of UFLS, SPS, phase-distance, and other relay types.
Yes
It would seem like Transmission Planners and Planning Coordinators would have a natural interest in modifications made to relay systems. Their simulations must show that BES performance under various contingencies meets certain criteria. Any information discovered in the course of the Protection System Studies would be of interest to them as well.
No
This requirement assumes that a material percentage of the many thousands of interconnecting relay systems has a problem. There is no evidence of this; and in fact, the Rationale text box for R1 states that the converse is true. This makes sense, as the inter-operation of Fault isolation Protection Systems is a fundamental and well-understood concept – which may not be the case with the more complex relay types. In our opinion, the two-year TO assessment will be sufficient to catch an issue and drive improvements afterwards. Therefore requirement R1.1.1 should be deleted. In addition, we do not agree with the "on or subsequent to June 18, 2007" time frame, since these studies are completed when a facility is built, and/or when a facility is significantly changed, which could quite possibly be prior to 2007. If studies were completed before June 18, 2007, and nothing significant has changed, the study meets the PRC-027 requirement, and/or the TO assessment does not indicate a need, there is no purpose served by repeating the study.
Yes
Ingleside Cogeneration LP agrees that a 10% delta in Fault current is material and would warrant further study. However, we are not sure how these studies would correlate to those managed by Planning Coordinators and Transmission Planners. It seems like these entities would have to be involved in any studies that may result in a change in relay settings or a Protection System upgrade.
No
Ingleside Cogeneration LP believes that the coordination process developed by the project team is redundant with the one established in FAC-002-1. If there is a material change made to a Facility, the process should be captured in a single reliability standard.
No
In general, Ingleside Cogeneration LP believes that a material unplanned change must be communicated to neighboring Facility Owners. However, this should not include an emergency replacement in kind due to a failure. This is a repair only which does not change the characteristics of the relay or the associated BES components – and therefore has no impact on interconnected owners.
Yes
It would seem that M9 should be reworded slightly so that it is clear that the compliance burden is placed on the party sending the confirmation. It seems like it should read "demonstrating the confirmation was sent within the respective time frames" instead of "demonstrating the confirmation was achieved within the respective time frames." In other words, Requirement 4 compliance is solely for the confirming party to show evidence, not the submitting party.
Individual
John W Miller
Georgia Transmission Corporation
No
The title should state the same as the purpose. Example: "Protection System Coordination of Interconnected Facilities". The purpose is to make each entity communicate protection system and/or facility changes in order to make coordination changes as needed.
No
Yes
No

Using "V" to denote fault current values may help the non-engineer reading the document, but "I" is the common nomenclature for current in the utility industry. The equation in R2.2 should use "I" in place of "V". There is a risk in using calculated fault currents of the most recent PSS and not existing relay settings. If the entity uses 10% margin in settings it will be too late to make settings changes. Should the margin be based on existing fault calculations and existing relay settings basis?
No
The parenthetical comment in R3 should be deleted. R3.1 lists the items that would trigger the need for notification between entities. Once notified of modifications, the entities will communicate documentation needs. R3.2: In the case of major BES equipment failure, there is a more pressing need to notify an interfacing entity that there has been change that could affect fault magnitudes. The 30 calendar days may be too long for such occurances and 2 business days would be more in consideration. R3.3.1 may interfer with PRC-004-# time schedules for misoperation followups and investigations. R3.3.2: Refer to comment above regarding R3.2.
Yes
Yes
Yes
Meets NERC time frame practice.
Group
Salt River Project
Bob Steiger
Yes
No
No
The requirement to provide a copy of each Protection System Study is an administrative burden that does not reflect the intent of Results Based Standards. Changing the requirement to maintain evidence that Protection System Studies are coordinated and affected entities have agreed to the results of the Studies is adequate.
Yes
Yes
Yes
No
This is too long; 60 days should be adequate
Individual
Dale Fredrickson
Wisconsin Electric Power Company
Yes
No
The previous version, we think correctly, did not include DP's in the applicability. Since the revised definition of the BES is currently awaiting FERC approval, the applicability of this standard to the Distribution Provider function is not appropriate. The relevant entities should be limited to TO and GO only.

No
In some cases there may be many Interconnected Facilities between two or more owners. It cannot be expected that owners will be able to support performing multiple studies in parallel, at the same time. It would be best to eliminate the specified timeframe, and allow the owners the latitude to determine the timeframe based on priorities decided by them. Also, replace the phrases in R1.1.2 and in R1.1.3, "… unless the entity can demonstrate such a study is not required", with "unless the entities involved agree that a study is not required". If the interconnected entities agree that a study is not required, there should be no requirement to document the reasons why a study is not required. Likewise, revise M1 to include as acceptable evidence "documentation that the relevant entities have agreed that a study is not required."
Yes
No
1. R3 should have the phrase "shall notify…" in the requirement, not simply "shall provide …the details". This should be a requirement for entities to provide a notification to other entities that some changes are being planned which may affect Protection System coordination. 2. The wording in R3.1 is unclear as to the intended scope of the qualifying phrase, "when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities." It should be made clear that ONLY those changes which affect coordination need to be communicated to other entities, whether at new or existing Interconnected Facilities or other facilities. If this is the case, then some of the comments below may not apply. 3. Also in R3.1, the bullets for "changes" in transmission systems and generators should be modified by the word "significant". Likewise, a "replacement" of an Element, or relay, or other device, may not require any change in relay settings, so the wording should be modified by "replacements which require protection setting changes". The bullet for changes to generators should also remove the "re-ratings" term, since a re-rating of a generator typically affects output power, but does not change the impedance. Indeed, there may be many minor changes which fall in the current R3.1 list which may have little or no effect on fault coordination, and therefore should not trigger a requirement for a notification or a study. Also, changes to CT or VT ratios do not necessarily result in a change in primary quantities, so these references should be removed. 4. R3.2 should be revised to require an entity making significant changes to provide the data to the other affected entities, without the need for the other entities to request it. 5. The R3.3 requirement (3.3.1 and 3.3.2) to notify other entities within 30 days for changes made following a Misoperation or failure is too restrictive. A timeframe of 60 days would be more appropriate. Also, as above, these requirements should only be applicable when the changes made have a "significant effect on coordination." A requirement to make notifications for changes unrelated to Interconnected Facility coordination will not serve the objective of increased reliability, and only increases unnecessary compliance documentation. 6. M7 (last phrase) should be revised to "…or absent such an agreement, within 30 calendar days of a request."
No
The requirement to reach agreement on Protection System changes prior to the project in-service date is not realistic and should be removed. While the entity that is initiating a project has a responsibility under R3 to notify other entities in order to perform a study, there is no required timeframe for these notifications to occur. Unless the initiating entity has a requirement to provide data under R3 in a timeframe sufficiently ahead of the in-service date, this is a requirement that may be impossible to achieve.
Yes
The SDT is to be commended for their efforts in what is a very challenging standard to develop. A Protection System Study by definition must assure that Protection Systems are "coordinated" at an Interconnected Facility. However, this standard does not establish any ownership for achieving a complete study. The interconnected entities are only capable of studying the portion of the system that they own. So, each entity performs their portion of the study and communicates it to the other entities. Thus, there is a lack of clarity in the standard about how the complete study gets done and is documented. With the possible exception of the Transmission Owner, no entity alone has the complete system model that is essential for documenting the complete coordination study. There is

also ambiguity on what a complete study looks like, and is subject to interpretation. It is unclear how the supplementary documents previously developed for PRC-001 apply to this standard. In the absence of such guidance, how will consistency be achieved for coordination of Protection Systems on the various types of Interconnection Facilities ? It is suggested that Requirement R4.3 is extraneous and should be removed. If these changes are sufficient to trigger a study, then the timeframe for agreement is already specified in R4.1. We propose that the standard be revised to allow the entities to re-affirm the results of a previous study, when appropriate, rather than needing to perform another study. For example, perhaps the fault current has increased, but the coordination interval between devices is not appreciably changed. The SDT notes in several places in the draft standard (pg 6, 16) that there is no evidence of widespread miscoordination between Interconnected Facilities, nor any evidence of misoperations caused by lack of coordination. This suggests that if this standard is needed, that it should be simpler, less prescriptive, and have greater recognition of the motivation for mutual coordination that already exists. It can be argued that the tasks and time frames required in the draft standard should be left to the entities to determine.
Individual
Rich Salgo
NV Energy
Yes
Yes
No
With such a long time frame for conducting this subject study, one cannot assure that the protection systems are coordinated, and there could be an impending mis-coordination that goes uncorrected. Suggest 12 or 24 months.
Yes
Yes
Yes
Yes
Yes
While we agree the Protection System Sutides are necessary to verify coordination of Protection Systems, we believe that the proposed Standard requires more than the necessary amount of documentation, and therefore becomes administratively burdensome. This is contrary to the principles of the Results-Based Standards. We suggest that the evidence be limited to evidence that studies were coordinated adn that the applicable entities have agreed to the results of the studies.
Group
Detroit Edison
Kent Kujala
No
It is suggested that “. . . the system performance specified within requirements established in other approved NERC Reliability Standards” be specified so that what needs to be met is clear.
No
No
Why aren’t studies performed prior to June 18, 2007 considered acceptable if they’re still valid as long as no significant fault current or system changes have occurred?
No

Recommend that the “trigger” be a system change (line, transformer, generator) that results in an impedance change.
Yes
No
Recommend that if protection system changes due to emergencies need not be agreed upon before installation, then this should be stated more directly in the standard.
No
It appears that the “initiator” has 90 days after completing the study to provide the information while the other entity has 90 days to review and respond to the request. Suggest that a longer response time frame be considered since the “responder” may need significant time to review changes.
No
The proposed VSL for R4 appears to imply that the “receiving” entity has no other choice but to confirm agreement. If the “receiving” entity has concerns with the study or changes, both parties should be responsible for resolving the issues.
It is suggested that the standard include other relevant information that could be needed for a protection system study such as critical clearing times determined from stability studies. In Figure 3, what Protection System Studies would be required if the Distribution Provider does not have a Protection System designed to protect BES transmission system elements? Also, please clarify if the transformers in Figures 3 and 4 are BES elements. Also, further clarification, including some examples, would be beneficial to explain what does and what does not constitute “Protection Systems installed to protect Transmission System Elements” by a Distribution Provider.
Individual
Kayleigh Wilkerson
Lincoln Electric System
No
LES is concerned with the significant amount of data and information an entity would be required to share as part of R3. As an example, if a CT ratio on a secondary relay with no pilot tripping is changed, but does not change the intended response of that relay, then there is no reason to share that information simply for the sake of sharing it. Entities should be allowed some amount of discretion regarding the information to be shared amongst other entities.
LES recommends additional clarity be added to explain how an entity would coordinate the efforts of the many different protection schemes - for example, pilot tripping, primary, secondary, ground overcurrent, breaker failure, LOP supervised, etc. - to determine only Elements required to isolate Faults are removed from service. Does an entity consider only its fastest scheme, slowest scheme, or all of them? Additionally, is an entity to consider contingencies such as primary or secondary relay out of service, loss of communications, etc.? What about backup tripping? Until the above is addressed, an entity will have a difficult time discerning what exactly needs to be studied. Please take into consideration that system protection is a complicated subject and each entity has its own philosophies on how to do it. Entities should be allowed to use their individual engineering judgment when designing their systems and ensuring it will work to their own standards as well as in compliance with the NERC standards. LES is concerned that there may be potential for mis-coordination between PRC-027-1 and PRC-004-2a. If a misoperation is defined as tripping too much out of service during an event, does the entity become instantly non-compliant with PRC-027-1 since it should have been studied not to do so? Any correlation between these two standards should be considered and clearly defined. LES recommends the 24 month timeframe specified in R2.1 be extended to 60 months.

Historically, fault currents tend to increase gradually over time; therefore, an entity may never see a 10% increase between studies, but will most likely see a 10% increase over a larger timeframe at which point they would never be required to perform a study.
Individual
Mike Weir
Dairyland Power Cooperative
No
The NERC Protection System definition includes more elements than would need to be coordinated at interconnecting facilities (e.g. batteries, chargers). Please consider revising to include only the protection elements that would need to be coordinated to remove Elements from service to isolate Faults.
No
It is unclear how the requirements of this standard apply to entities that fulfill multiple functional roles. For example, an entity is registered as both a Generator Owner and Transmission Owner. In the case where a GO and TO are the same entity is it required to show the same type of coordination?
No
It is agreed that the there needs to be a time period for Protection System Studies to be performed after the standard takes affect. However, the length of time is a concern due to the industries existing resources. It would be preferred that the time period be lengthened to 60 months.
Yes
Yes
No
How is it to be handled if two entities do not agree to the same approach?
Yes
Yes
R2, 2.1 “Perform a short circuit study to determine thepresent Fault current values, not less than once every24 months.” is excessive. Yes, short circuit databases are updated annually or even more frequently at times based on system changes. However, to require a full short circuit study every 24 months is too frequent. Changes on the system don’t necessarily warrant a full short circuit study, but maybe a study for the affected area. This is adding an unnecessary burden to the industry.
Group
Western Small Entity Comment Group
Steve Alexanderson P.E.
No
The language “…remove from service only those Elements required to isolate Faults…” is problematic. Taken literally; only the faulted Element may be isolated, and any adjoining buswork or lines (separate Elements) must remain energized; even the result is no change in the loss of load or capacity. We suggest ““To coordinate existing Protection Systems…” to ensure that this is not interpreted as a construction standard requiring additional Protection Systems.
No
Yes
Yes
No
R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination

studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward.
No
R4.1 as written apparently requires receiving entities to always agree with the initial study, even if they see flaws that would lead to miscoordinating Protection Systems. Suggest that “confirm” be replaced with “reach.”
Yes
No
We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in “guidelines and Technical Basis” that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.
The comment group agrees with the WECC Position Paper that the standard as written requires excessive and burdensome documentation that is not needed to demonstrate coordination.
Group
Operational Compliance
Ed Croft
Yes
No
Yes
No
We agree with the 10% value, but not with the actual wording in the Standard. (The Standard reads "2.3 Where the calculation performed....indicates a deviation in Fault current of 10% or greater". It is not clear whether this means 10% Fault current deviation above or below, both or just above. We also suggest that specific defined trigger events prompt a Fault current review for affected Interconnection Facilities, instead of fault current reviews being required every 24 months for every Interconnection Facility.
Yes
Yes
We suggest that R4.1, R4.3.1 and R4.3.2 all have a time period of 90 days.
Yes
Yes
All of the questions in this survey should elicit a "yes" response to agree with the Standard. Question 2 elicited a "no" response even though we agree with the part of the standard in the question. The questions in this survey should be worded to ask if we agree with the exact wording of the standard. For example, in Question 4 the wording of the question is different than in the Standard regarding deviation.
Individual
Deborah Schaneman
Platte River Power Authority
Yes
No

No
There is no need to have a Protection System Study available for review of every Interconnected Facility. The results based objective is that the registered entities communicate and coordinate. a simple statement by both entities that they have communicated and coordinated is sufficient.
No
The selection of a +/- 10% change in an Interconnected Facilty's Fault current value is arbitrary. The results based objective is to communicate and coordinate.
Yes
Yes
No
We believe the agreement must be reached prior to implementing the changes. This requirement is burdensome on the entity for record keeping and does not add reliability to the BPS.
Individual
E Hahn
MWDSC
Yes
No
No
Protection Systems installed prior to June 18, 2007 should not be required to redo a study because a system study should have been performed prior to installation based on the interconnected configuration at that time. The interconnected systems will change over time and redoing studies will raise more questions on assigning responsibility for changes beyond the control of the protection system owner. For protection systems installed prior to June 2007, TOs should only be required to show a study was performed and coordinated with appropriate interconnected entities.
No
Every TO should not be required to perform a short-circuit study every 24 months if there were no significant changes to that TO's BES facilities. Changes in adjoining interconnected BES systems could change short-circuit duties for an adjoining TO's system. The TO whose BES changes should be responsible for performing short-circuit duties on all adjoining systems as part of Requirement R3. In addition, FAC-002-1 requires TOs to coordinate with TPs and PAs in the assessments of proposed new facilities, including evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission through steady-state, short-circuit, and dynamics studies.
Yes
Yes
No
More time than 90 days may be needed to reach agreement for complex system changes or because of conflicting study priorities. Allow more flexibility for the parties to agree to a time, not to exceed, e.g. 180 days.
Yes
The standard requires more documentation than is necessary and providing a copy of each Protection System Study is burdensome and would not result in better performance. It should be adequate to document that studies were performed and that affected entities have agreed to the results.

Individual
Angela P Gaines
Portland General Electric Company
Yes
No
Yes
Yes
No
No, Add facility ratings and define transmission line impedance tolerance (see question 9 response)
No
No, see question 9 response
No
No, It depends upon what constitutes a Protection System Study (see question 9 response
No
No, Severe VSL for lateness should only apply to R4.
This standard, as written, requires an inordinate amount of documentation that this not in line with current fault study and protection coordination tools. When combined with the timelines, this will require a complete rework of the existing processes used for protection coordination and an additional full time protection engineer. We have no history of misoperations on interconnecting lines or of backup protection on such lines to justify any additional effort to document coordination. R1 leaves open to interpretation what constitutes coordination, with many unanswered questions. What is an acceptable coordination margin? How many contingencies need to be considered? Does loss of communication need to be considered? For the evidence, would an exception report showing no coordination intervals are violated be acceptable for the “summary results of each Protection System Study”? Will the responsibilities outlined in the Application Guidelines be included as part of the final standard? These may not be in line with current practices. How will this requirement be audited across utilities with different coordination practices? R2 requires significant cooperation between interconnecting utilities, with each keeping track of what fault currents are being used by the other. This is not in line with the use of joint system models, allowing more frequently updated fault currents to be used. Currently, the individual system models are updated by some utilities daily then they are reconciled at least annually. Protection System Studies can be run any time in between model reconciliation, with all local changes accounted for. R3.1 does not provide guidance on the timing of notification for changes; the measure M6 indicates this is for future changes, but the requirement does not. Protection engineers are rarely notified in advance of transmission line changes resulting from such things a road widenings and pole replacements. Providing this information to neighboring utilities in advance will require significant changes to line design processes. Thresholds must be established to rule out minor transmission line changes that do not significantly impact the line impedance (and thus the fault current); perhaps a 10% change in impedance would be more appropriate than the general “changes to line lengths and/or conductor size or spacing”. This requirement should also include changes to facility ratings to ensure PRC-023 compliance. R4 requires a significant change to work practices to support capital construction schedules and allow interconnecting utilities 30 days to review changes. The schedule laid out does not account for disagreements that lead to back-and-forth prior to achieving agreement. This requirement grants power to neighboring utilities to halt construction activities which could, in turn, create compliance violation of other Reliability standards.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes

No
ATC is not aware of additional functional entities that should be included.
No
ATC does not agree with the time frame proposed. The existing requirements in PRC-001 do not require protection system studies with Distribution Providers. As such, even though studies have been completed there may be no package (documentation) to support an audit. This requirement assumes that, if there is no existing fault study, one needs to be completed. If there have been no changes in short circuit or protective schemes, allow for completion of the studies based upon prioritization using voltage class and loading level.
Yes
ATC does agree with the premise of the a 10% change but feels that the SDT needs to provide a clear definition of which fault current must change 10% to trigger the notification requirements and initiation of a protection study. Fault current on an interconnecting line may change very little even though bus fault contributions from other lines may have increased considerably, affecting in feed current and relay settings.
No
ATC does not agree with the list as written and recommends the following changes: ATC suggests that Requirement 3.1 bullet 2, be revised as follows: Changes to line lengths and/or conductor size or spacing that result in significant impedance changes. As an example, an interconnected line may need to relocate a pole because of a road move. This may alter slightly the length or spacing of the line but does not result in a change to the impedance. If no impedance change occurred, no relay settings need to be changed and there should be no additional coordination. ATC suggests that Requirement 3.1 bullet 3, be revised as follows: Additions, removals, or replacements of transmission system Element(s) that is significant. An Element may be replaced with an equivalent device that does not require a relay setting change. If no relay settings need to be changed, there should be no additional coordination.
Yes
No
ATC does not agree with the 90 day time frame. ATC also has the following recommendation: Requirement 4.2 states that Interconnected Facility Owners confirm that coordination is agreed to prior to placing equipment in-service. ATC believes that R4.2 is adequate to cover coordination. Therefore, the SDT should strike R4.1 and R4.3.
No
The VSLs, in general, are much more severe than the risk to the BES and should be rewritten to more accurately reflect the risk. For example: if a BES Element is replaced “like for like” with no material impact to the associated settings and a failure to notify by more than 30 days occurs, the issue is assigned a Severe VSL yet there was no effective change to BES reliability.
In general, ATC agrees with the need to modify PRC-001. However, PRC-027 as written expands the scope of PRC-001 by including Distribution Providers (DP). The SDT, on both page 6 and 16 states that there is “no evidence of widespread miscoordination between Interconnected Facilities…” They further state on page 16 that “Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperation.” Based on the above statements, ATC questions the need for the level of prescription in the standard. ATC asks the SDT to update the numbering for measures to match the requirement numbering. Reliability Standard TPL-001-2, which has been approved by NERC BOT, requires short circuit analysis. ATC believes that PRC-027-R2.1 is duplicative.
Group
Pacific Gas and Electric Company
John Hagen
Yes
No

No
PG&E we believes that the 6 calendar month time frame in requirement R1.1.2 is too short and should be extended to 12 calendar months
No
The requirement to run the fault study to determine if there is any 10% change is only required once every 24 months per requirement R2.1. But if you run a batch study and find a bunch of 10% changes, you only have 6 months to do all the coordination studies. We think a 12 month window for performing the coordination studies is more appropriate.
Yes
Yes
No
12 month time frame may be required to resolve the technical issues that typically prevent agreement
No
do not line up with proabability and potential severity
Group
Northeast Power Coordinating Council
Guy Zito
Yes
No
From a reliability perspective, the Applicability Section of PRC-027-1 should not include the Distribution Provider because the TO is responsible of coordination of the protection with the DP.
No
Agreed that a change in fault current is a method to trigger a coordination study, but a 15% threshold would be more efficient (+/- 15 %). Clarify where the fault is to be applied and where the deviation is to be observed. One possibility is to apply the fault at a bus at one end of the tie and then determine the deviation in the current in each element connected to that bus.
No
DP must be excluded from R3. See the response to Question 2.
Yes
What happens when consensus is not reached between two parties? The TO should have the responsibility for coordination.
Yes
For studies of an entire system or all of its interconnections, those persons doing the study should only be responsible for reviewing the study results for those interconnections in which they participate. The wording in the text demands that the results be agreed with. The text should be reworded to require a response (not necessarily agreement) within 90 days and only pertain to the portion of the study applicable to interconnections participated in.
Yes
1. Referring to the Example Process on page 22, it should not be the responsibility of Entity B to propose revisions. It should be the responsibility of the Entity in the better position to propose a revision to propose the revision. There needs to be flexibility as to who is obliged to come up with a revision. 2. Regarding Fig. 2 and Fig. 5 in the Application Guidelines, it is important that the expertise of each entity involved in an interconnection be used to ensure that there are no coordination issues.

For example, Generator Owners and Transmission Owners. 3. Application Guidelines Fig. 3 requires the TO to verify that the DP's and the GO's protection systems coordinate with the TO's, even though the GO doesn’t connect directly to the TO. It should be the DP that checks coordination of the GO with the DP for faults on the transmission side of the DP's substation transformer, and the TO that checks coordination of the DP's transmission protection with the TO. If all of the transmission protection is back at the GO (in other words the DP has installed no transmission protection at its sub) then to do as this app guide suggests the TO will require an accurate short circuit model of the DP's system between the GO and the TO. It would require that the DP keep the TO continuously appraised of changes to the DP's system that impact the short circuit representation. Considering the proliferation of distributed generation being interconnected to distribution systems the burden should be on the DP not on the TO supplying the DP to verify coordination. The scope of the text "....generator protection systems...." should be narrowed so a TO or DP is not responsible for the coordination of devices it doesn’t own, maintain or set.
Individual
Rick Koch
Southern Minnesota Municipal Power Agency
I agree with and support the comments of the MRO's NERC Standards Review Forum (NSRF).
Individual
Don Schmit
NPPD
No
Suggestion: Remove “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” since there are other standards that are or will be in place otherwise it sounds like the other standards must have evidence included for this standard documentation as well. Perhaps this standard is not required if the other performance standards are adhered to or have portions of this draft standard included in them.
No
This applicability needs clarification. How does this standard relate to the definition of BES? Does including Distribution Providers mean an entity that does not own a transmission protection system is included under this standard? There needs to be clear understanding that radial feeds on load serving transformers such as 115/69kV or 115/34.5kV transformers and low voltage feeders are not included in this standard. Perhaps NERC needs a program to evaluate/identify all functional entities and determine if they should be registered and thus applicable and not have utilities try to determine the status of other utilities or functional entities. Clarify if the Transmission and Generator owner are the same utility how sharing of information is documented or confirm that this relationship means the documentation is not applicable in this standard.
No
To mitigate compliance risks for various types of data formats for existing studies and studies older than June 2007 this standard will likely require utilities to go back and update all data so that it meets the requirements and description of evidence in the application guidelines when the requirements become enforceable. This could likely take longer than 3 years. I would recommend more time such as 6-10 years (time depends on the number of applicable system ties as well)
No
Monitoring for a 10% change in faults could trigger studies that are not needed and it is not necessarily a good indicator settings updates are needed. It would be more practical to require a

review of settings on a set interval (5 years) or as required by R3.
No
Section 3.3 should clarify if the corrections change the coordination then other entities should be notified.
No
Recommend the drafting team should consider several scenarios to help determine issues that will arise with putting into practice this standard with the time lines included. Some scenarios I can think of are: 1. who is liable or fineable if a required approval reply for a protection study is not made in a timely manner to a Transmission owner. It is imperative not to hold a utility responsible for another entities lack of timely responses. Theses issues will create murky situations when the Transmission owner does not have control over external entities ability to respond to notifications of changes within specified times. 2. If a Distribution Provider is not registered is the Transmission owner responsible for getting a reply or approval of a protection study?
No
This requirement does not allow for various scenarios or conditions in the process of doing business. For example, multiple phased work or longer lead time projects where designs may change. It would be better that there be verification that studies were performed prior to in-service dates rather than tracking detailed time lines which could likely be complex and difficult to judge for audit start and end dates.
No
The time lines monitored down to 10, 20 or 30 days appear to be impractical in terms of monitoring for facility owners and in terms of auditing by compliance entities. This diverts the focus or sharing the data in a timely manner prior to project in service dates.
On page 6 and 16 there are statements such as “no evidence there is widespread miscoordination between Interconnected Facilities…” and on page 16 “Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” Clarify what the need is for this standard? This proposed standard significantly increases the record keeping requirements and subsequent resources needed for each Facility owner but does not appear to have a justification. I find the numerous time lines will create significant confusion and very complex data retention practices that will be difficult to track and difficult to audit. It appears the focus is more on time lines and the likely result is the content of the shared information will likely suffer due to the burden of tracking communications between entities. This draft standard includes time lines ranging from “prior to in service date, 30 days, 60 days, 90 days, 6 months, 2 years and 3 years”. I suggest fewer and longer time lines with the focus on if the sharing of information took place and not on when did it take place. The SDT statement below should be generalized to the standard as a whole: “The SDT believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the SDT sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable “prior to the in-service date,” Clarify the size of generation for Distribution Providers that would make this standard applicable for all involved entities. I would expect that the BES phase II definition or registry criteria would be referenced.
Individual
Brian Evans-Mongeon
Utility Services
No
The purpose should specifically state whether or not this standard applies to BES Elements or all Elements. In consideration of other PRC reliability standards, this standard uses language that implies applicability to all Elements. Under the NERC Standard Development Process, standards are only to be applied to BES equipment, unless the applicability language specifically states a broader application. This standard implies it but does not specifically state it. The standard should be modified to clear up any confusion.
No
However, using the broad term "Protection Systems", this SDT is broadening the scope of the

standard beyond the BES. Due to the recent direction in Project 2007-17 for PRC-005-2, Protection Systems has been expanded to include systems beyond the definition of the BES. This project should limit the applicability for the DP to "transmission Protection Systems" as identified in PRC-004 and 005-1.
No
This requirement if left as is, would create a potential double jeopardy situation if a violation occurs. Under FAC-002, entities already have the obligations to communicate and coordinate the integration of new, replacement, or upgrades on existing facilities. We view this requirement to be a duplication of that standard and creates a double jeopardy situation if a violation were deemed to have occurred.
No
See comment to Question 5.
No
Group
MRO NSRF
WILL SMITH
Yes
The last part of the purpose, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" is vague and open-ended. The NSRF recommends that the SDT refer to the TPL standards if the intent is to limit responsibility for correct coordination to studied system contingencies
No
The standard includes the definition of Interconnected Facilities as BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities. It is unclear how the requirements of the standard would apply if a registered entity would fulfill more than one functional entity role. For example if a registered entity was both a Generator Owner and Transmission Owner would the requirements of the standard apply to the interconnection of the generator and transmission facilities? It is recommended that the standard be modified to provide clarity for this situation.
No
If an entity has a Protection System Study performed prior to June 18, 2007 that meets the requirements for the study specified in PRC-027-1 and there have been no changes to trigger a new study as specified in PRC-027-1 (that have occurred) the study should be acceptable for compliance with the standard. It is suggested that the requirement R1, sub-requirement R1.1 be revised by removing the phrase "that was performed on or subsequent to June 18, 2007." The NSRF questions if 36 months is ample enough time for large company to get all studies done within 36 months. Unless R1.1 is revised to mean all studies regardless to when it was performed.
The NSRF recommends that a clear definition of what fault current must change 10 % to trigger the notification requirements and initiation of a protection study. Fault current on an interconnecting line may change very little even though bus fault contributions from other lines may have increased considerably, affecting in-feed current and relay settings. It would be easier to implement a time-based periodic review of settings every 5 – 8 years (or sooner if required by conditions in Requirement R3). R2 is redundant and could subject entities to double jeopardy in conjunction with the new TPL standards which will require annual short circuit studies and NERC studies should not be duplicated to avoid double jeopardy. At a minimum, the 24 month requirement should be changed to at least every 2 calendar years. This would align with the annual requirement for the TPL standards. The new TPL standards are in limbo with FERC's rejection to footnote b.
Yes

No
The NSRF agrees in general but questions how to handle situation where neighboring utility are unable or unwilling to meet required timetable? Recommend the SDT explain the process for conflict resolution. Requirement 4.2 seems to mandate agreement with proposed changes which seems to go beyond the scope of the standard which is stated as “to coordinate Protection Systems”. It is suggested that this requirement be rewritten to require agreement that proper coordination will be maintained when the changes are implemented. In a similar way requirement 4.3 should be rewritten.
Yes
Yes
Recommend that the wording of R2 need be modified to allow a grace period for implementation, as was done in R1. As written, R2 requires an immediate short circuit study, even if no protection system study is required by R1.1.1. The SDT, on both page 6 and 16 states that there is “no evidence there is widespread mis-coordination between Interconnected Facilities…” They further state on page 16 that “Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” Why, then, is this standard even needed? It adds an onerous burden of record keeping on each Facility owner without justification for doing so. Since these are still zero defect standards, should exceptions be included for required operational replacements due to events (e.g. such as storms or immediate equipment replacement). When the lights are out and a technician replaces a CT or VT with a slightly different ratio but compensates by altering the relay settings, there is no way to perform an instant system protection study when the equipment change out was required to support system reliability. The NSRF understands that a “planned” changed be studied before hand, but how will this be viewed when a change is needed that is “unplanned”? Please clarify
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
No
PRC-027 appears to have been written exclusively for vertically integrated power companies, and there is no justification for making the proposed standard applicable to independent GOs. The only role an independent GO fulfills in isolating faults is to trip the breaker if the generator or GSU has a problem; everything involving sequencing is in the Transmssion Owner’s (TOs) or Distribution Providers (DPs) system. Independent GOs are owned by separate legal entities than the applicable TO or Distribution Provider [DP] to which they are interconnected. Such GOs do not have the capability to perform the type of TO/DP system studies that appear to be contemplated by the SDT. The actions required of independent GOs should be to perform Protection System maintenance and supply data to other applicable entities, per existing standards PRC-005-1 and PRC-001-1.1, respectively.
No
Applicability to GOs should be limited as stated above in question #1.
No
As noted in the response to question #1, TOs and DPs have the data and the capability needed to perform the studies that appear to be contemplated by the SDT.
No
See comment in question #1 above.
No
See comment in question #1 above.
No
See comment in question #1 above.
No
See comment in question #1 above.
No
See comment in question #1 above.

The cutoff date of 6/18/07 for grandfathering of studies may be appropriate for TOs and DPs in light of changes over time to their systems, but the studies that originally established GO relay settings would still be valid where the equipment has stayed the same. For the reasons discussed above, there should be no applicability of PRC-027 to independent GOs, and no changes to PRC-001-1.1 because the applicable requirements.
Group
SERC Protection and Control Subcommittee
Joe Spencer
No
a) Recommend under Purpose, deleting: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet ‘the system performance specified within requirements established in other approved NERC Reliability Standards’ and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003R1.3.7 already requires the entity to “demonstrate that system performance meets its Table 1 for Category C contingencies” (TPL-001, -002 have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1. b) The term “coordination” should be removed from the new standard Title and Purpose. Recommend changing Title to “Protection System Interconnected Facility Performance during Faults”. Also recommended is to change the Purpose to read “To communicate and exchange Protection System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those Elements required to isolate Faults.” c) In PRC 027, using the term coordination should only be referenced when referring to the technical aspects of the relay coordination within a requirement when applicable. (In the current PRC 001 standard the meaning of the term “coordination” has, and still is, interpreted in two ways. One interpretation is viewed from the technical aspect as “relay coordination” and the second is viewed from an inter-communication aspect as “coordination of information” between entities).
No
Yes
Yes
a) In R2 2.2, replace the term “deviation” with “change.” (Note: For this calculation, all that is required is to calculate percent change. For example, Webster’s dictionary definition of “deviation” is: 1) a variation that deviates from the standard or norm; "the deviation from the mean” 2) the difference between an observed value and the expected value of a variable or function.) b) In R2 2.2, replace the term “present” with “new” and the term “most recent” with “previous”. Also reflect this terminology change in the %Change equation. (The use of the terms “present” and “most recent” can be perceived to be the same.) c) It is also recommended that “V” for value be replaced by “I” for current. d) In R2 2.1, please add “new”, delete “present” and add either “under normal conditions” or “maximum system conditions” so that it states “Perform a new short circuit study to determine the Fault current values under normal conditions, not less than once every 24 months.
No
a) Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout this standard already address notification requirements. b) In R3 3.3.1, change requirement to read: “Changes are made to a Protection System as a result of findings during misoperation investigations, commissioning, or maintenance activities.”(The current wording implies that all findings are due to errors. The reference to errors should be removed and the emphasis of this requirement needs to be placed on “changes” made to Protection Systems when it becomes apparent that a change is required which impacts coordination of relays.)
Yes
Yes

No
We recommend a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale, this urgency is not warranted. Most entities will have numerous Interconnection Facilities, so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: • Lower VSL should be 30 days late. • Moderate VSL should be more than 30 days, less than a year. • High VSL should be more than a year but done. • Severe VSL should be more than a year and not done.
a)Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1-1.1.2 reads - “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.” For Requirement R1-1.1.2, recommend omitting the reference to R2 and reword so that the requirement is specific. Recommend changing to read: “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required”. b) The standard uses different formats for identifying deadlines. Sometimes “days” are used and sometime “months” are used. It is suggested that a common format be used. c) Please note that there appears to be an inconsistency in the 24 month requirement of R2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1, which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual requirements where time schedules are involved, the wording of the requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the time schedule at the beginning of the requirement whereas R1-1.2 references the time schedule at t the end of the requirement. Recommend using a standard wording format and list the time horizons in the beginning of the requirement in all requirements that have time requirements involved. For Requirement R1-1.2, recommend changing to read: “Within 90 calendar days after the completion of the Protection System Study, provide to each affected Interconnected Facility owner a summary of the results of each Protection System Study performed (including at a minimum the Protection System(s) reviewed and any proposed revisions).” e) There is a concern with the various time requirements for studies, notification, and replying.Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. i) The overall process would be less burdensome by changing the R2 2.1 to “not less than once every 5 calendar years” which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above).Our experience is that the vast majority of Protection System Studies are triggered by R3. ii) The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. iii) Omitting “project schedule” from R3 would streamline data exchange. f) Delete “operating” from the Interconnected Facilities definition because different functional or corporate entities sufficiently capture all of them. We also suggest defining the singular Interconnection Facility, rather than the plural. “The comments expressed herein represent a consensus of the views of the above named members of the Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”
Individual
daniel
mason
Yes
No
Yes

Althought the timeframe appears reasonable, the more basic question about the necessity of the documentation requirements needs to be reconsidered.
No comment
No
Do not agree with blanket inclusion of replacement of the generator step-up transformer(s) on this list.
No
Each entity has its own philosophy and standards for Protection System design. In providing agreement to a third party design, a question of liability is also opened up. R4 should be changed from requiring agreement to requiring notification. There is enough incentive for entities to resolve material disagreements on Protection System design without the need for regulatory intervention. Regulatory involvement should only take place when business conditions call for it. Otherwise the result is higher production costs with no reliability benefit.
No
Do not agree with the need for documentation of "agreement with a Protection System Study" between entities. See Question 6 response.
No comment
Individual
Rowell Crisostomo
ATCO Electric
Yes
No
Yes
Yes
Yes
Yes
Yes
Yes
There are too many timelines that are hard to keep up with. The drafting team should reduce amount of timelines to a manageable amount.
Individual
Bob Thomas and Kevin Wagner
Illinois Municipal Electric Agency
Yes
No
Yes
Yes

No
Illinois Municipal Electric Agency (IMEA) recommends language be included in R3 (and elsewhere if needed) to clarify the R3.1 "generator unit(s)" is not applicable to a 20 MVA or less unit or behind-the-meter generation.
Yes
Yes
IMEA recommends language be included in 4.2 Facilities to clarify the standard does not apply to a DP protective device that only detects a fault on a transmission element and does not trip an interrupting device that interrupts current supplied directly from the BES. To minimize misinterpretation and potential impact on small entity resources, it would strengthen the standard if Section 4.2 Applicability language specifies the standard does not apply to a DP that does not own a BES Element/Facility.
Individual
Rhonda Bryant
El Paso Electric Company
Yes
No
Yes
It is unclear whether the proposed standard intends to reach 10% or greater deviations that accumulate over the course of a more extended period of time (i.e., greater than 2 years), or whether an entity can seek to perform multiple studies within a compressed period of time in such a way that it can ensure that a 10% deviation will not be reached from study to study, as illustrated below: • Study performed in Year 1 shows a 5% deviation • Study performed 12 months later (in Year 2) shows a 5% deviation • Study performed 12 months later (in Year 3) shows a 5% deviation [Cumulative deviation of 15% within 3 years, but only a 5% deviation from study to study]
Yes
Yes
No
EPE believes the timelines are not adequate when coordinating protection system studies involving sequential interdependence among parties for interconnected facilities. Timing of study data should correlate with any written agreements or procedures agreed to between the various parties. EPE also believes the documentation requirements within this draft Standard slow down the process, therefore increasing the time needed to complete and communicate the study data. Additionally, the proposed Standard fails to address two important and likely types of situations: (a) the situation in which an interconnected entity fails to respond to study results or to a planned change at the Interconnected Facility, or (b) the situation in which disagreements between the entities are not resolved within the proposed Standard's time clock.
Group
Colorado Springs Utilities
Jennifer Eckels
Yes
There are cases of weak system interconnected facilities where proper coordination may not be

achievable economically, except by severing the interconnect. Allowances should be made for these cases to prevent the severing of weak systems to meet this standard.
No
The wording of the text suggests that Interconnected Facilities include coordination and documentation of Transmission to Distribution interfaces. Since these are usually contained in different functional or corporate entities it suggests much more documentation, and needs clarified.
Yes
No
In order to avoid burdensome paperwork of traditional fault study values and existing fault study values, common thresholds should be determined for initiating a review. Common thresholds can be common device ratings, or agreed upon levels at interconnects. As in Facility ratings, each owner should have device ratings for device capacities and can include short circuit ratings, which if exceeded can initiate a review.
No
Specific project schedules can potentially cause violation of other requirements. A proposed change of conductor spacing, which can be interpreted as a change of one transmission structure requires notification to other entities, which we feel is excessive. Re-rating of generators rarely changes the protection, impedances or coordination involved. It is common to re-rate units depending on external factors to the generator which also provides excessive reviews and project schedule notifications. This section also implies notifications must be made after like and kind replacements of equipment found during misoperation investigations, but not those found during testing. On larger systems this requirement would be difficult unless notifications were made more than twice a month, which would require a large tracking system of who, what, and when information is sent to interconnected utilities.
No
This requirement seems to create a paper work burden that will add cost and lengthen the process of any and all transmission changes, unless there is some size significance added to the requirement under which a reduced process is involved. The maximum amount of paper work to complete must be assumed, unless there are specific limits set to restrict an overreach in how the regulation is applied.
No
Due to construction schedule requirements a 30 day approach should be taken.
No
If the requirements are not reasonable, the VRFs and VSLs are also not reasonable.
The wording of the text under Applicability suggests that Interconnected Facilities include coordination and documentation of Transmission to Distribution interfaces. Since these are often located in different functional or corporate entities we feel this would require more documentation, and therefore needs clarified. There are no specifications on what constitutes a significant change to a Protection System; is it a CT ratio change, a relay replacement, or anything to the whole system? For example, would a single structure replacement require notification as a line spacing change? The wording sounds good but lacks specifics that would make this a workable standard.
Group
ISO RTO Council SRC
Charles Yeung
No
Is the intent of the coordination that is expected limited only to those protection systems related to intertie facilities between facilities owners ? Or is the intent of the proposed standard to require coordination of protection systems to take into account outage and/or operating conditions between facilities owners beyond the immediate intertie facilities? In other words is this coordination requirement expected to be applied to relays that may not be directly involved in protection of intertie equipment?
Yes

Depending on the intent of the requirements as questioned in the comment to question #1, it may be necessary to include planners to provide data for contingent and varying operating conditions to coordinate relays beyond those dedicated to intertie facilities.
Yes
Yes
Yes
Yes
Yes
Yes
The SDT recognizes that Requirement R1 falls outside the scope of Poject 2007-06 and proposes that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. Left unaddressed, entities may be reluctant to vote to approve the PRC-001-2 changes. Changes made to a standard can cause unforeseen or unintended consequences that cannot be addressed because of limitations in the scope of the project. The SDT has no ability to address the matter without getting a change in scope of the project. This is a concern that applies to ALL standards changes as the industry seeks to revise and improve the NERC standards. A change in the Rules of Procedure or the Standards Development Procedures must be in place to recognize and deal with such occurrences. The SDT is also concerned that these proposed requirements are not conducive to NERC's stated goal of making the reliability standards more "results or performance oriented". Although many of the actions embodied in the proposed requirements should be performed, they are administrative in nature and do not in and of themselves provide results that will impact reliability. The industry needs to discuss and come to agreement on what reliability standards should look like in order to meet the NERC stated goal. The SRC also believes these requirements are not applicable for entities operating in the ERCOT Interconnection.
Individual
Steven Powell
Trans Bay Cable
No
The language "...remove from service only those Elements required to isolate Faults..." is problematic. Taken literally; only the faulted Element may be isolated, and any adjoining buswork or lines (separate Elements) must remain energized; even the result is no change in the loss of load or capacity. We suggest ""To coordinate existing Protection Systems..." to ensure that this is not interpreted as a construction standard requiring additional Protection Systems.
No
Yes
Yes
No
Comments: R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward.
No
Comments: R4.1 as written apparently requires receiving entities to always agree with the initial

study, even if they see flaws that would lead to miscoordinating Protection Systems. Suggest that "confirm" be replaced with "reach."
Yes
No
Comments: We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in "guidelines and Technical Basis" that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.
Comments: The comment group agrees with the WECC Position Paper that the standard as written requires excessive and burdensome documentation that is not needed to demonstrate coordination.
Individual
Daniela Hammons
CenterPoint Energy
No
The proposed term for Interconnected Facilities, shown on page 2 of 27 of PRC-027-1 Draft #1, is defined as "BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities." CenterPoint Energy believes Interconnected Facilities should be defined in reference to NERC registration and recommends changing the definition to "BES Facilities that are electrically joined by one or more Element(s) and are owned by different registered entities."
No
(a) The proposed term for Protection System Study, shown on page 2 of 27 of PRC-027-1 Draft #1, is defined as "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults." CenterPoint Energy recommends Protection System Study instead be defined as "A study that demonstrates Protection Systems operate as desired for clearing postulated short circuit Fault events." (b) CenterPoint Energy believes a 36 month implementation to have a documented Protection System Study completed for each Interconnected Facility is overly burdensome, unless certain Interconnected Facilities are exempted. CenterPoint Energy recommends exempting Interconnected Facilities that are serving only load and that are connected by no more than two transmission line Elements that are operating between 100 kV to 200 kV. Many of these Interconnected Facilities have fault-proven, time-proven protection system set points. Additionally, Draft #1, on page 5 of 27, notes that protection system misoperations related to coordination issues are addressed by PRC-004.
Yes
No
(a) Requirement 3 includes providing schedule information and project details to generation entities. There may be established market rules that provide for what information can be shared with competitive entities. (b) Requirements 3.1 and 3.3, with examples of what system and equipment changes require coordination, appear overly broad. Such requirements should only be "if applicable". R3.1, for example, specifies changes in line length. Certain changes of line length are immaterial to protection system set points. R3.3 requires coordination for the replacement of failed equipment. Replacing equipment "like function-for-like function" should be excluded from this requirement.
Group
Tennessee Valley Authority
Dennis Chastain
No

a) The term “coordination” should be removed from the new standard Title and Purpose. Recommend changing Title to: “Interconnected Facility Protection System Performance During Faults”. Also recommend changing the Purpose to read: "To communicate and exchange Protection System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those elements required to isolate faults." b) Recommend under Purpose, deleting: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” as it is superfluous and could cause duplicative or conflicting work. The purpose without this clause is clear, concise, and consistent with the rest of the 1st draft of this standard. The resulting coordinated Protection System must meet ‘the system performance specified within requirements established in other approved NERC Reliability Standards’ and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003 R1.3.7 already requires the entity to “demonstrate that System performance meets its Table 1 for Category C contingencies” (TPL-001, -002 have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1. c) In PRC 027, the term "coordination" should only be referenced when referring to the technical aspects of the relay coordination within a Requirement when applicable. (In the current PRC 001 standard the meaning of the term “coordination” has and still is interpreted in two ways. One interpretation is viewed from the technical aspect as “relay coordination” and the second is viewed from an inter-communication aspect as “coordination of information” between entities).
No
In some instances end-use customers, such as a large industrial load, take service delivery through an Interconnected Facility. It is not clear that the draft standard covers coordination between a TO and an end-use customer (not registered as a TO, GO or DP) who takes service via a BES Interconnected Facility.
No
"Protection System Study" is a new term being introduced with this standard. Since industry documentation of protection system coordination reviews are conceivably available from both before and after June 18, 2007, precluding coordination reviews performed prior to June 18, 2007 from acceptable compliance evidence could greatly increase the workload of protection system engineers during the proposed 36 month time period. Note that there is a possibility of overlap with the "Order 754 request for data" response period. The rationale statement for R1, Part 1.1.1, indicates that the effective date of PRC-001-1 was the basis for selecting June 18, 2007. PRC-001-1 primarily addresses new protective systems and changes (R3 & R5) and coordination with neighboring GOP, TOP and BA entities (R4). We suggest changing the wording of Part 1.1.1 to the following: “Within 36 calendar months after the effective date of this standard, if no valid Protection System Study for that Interconnected Facility exists.”
No
The 10% change is too narrow for protection system studies. Accuracies of PT, CT, wiring, and modeling all add together and therefore the threshold for a new protection system study should be 15%. a) In R2, Part 2.2, replace the term “deviation” with “change.” (Note: For this calculation all thats required is to calculate percent change. ie.Webster’s dictionary definition of “deviation” is 1) A variation that deviates from the standard or norm; "the deviation from the mean”. 2. The difference between an observed value and the expected value of a variable or function.) b) In R2, Part 2.2, replace the term “present” with “new” and the term “most recent” with “previous”. Also reflect this terminology change in the % Change equation.(the use of the terms “present” and “most recent” can be perceived to be the same.) c) It is also recommended that “V” for value be replaced by “I” for current. d) In R2, Part 2.1, please add “new”, delete “present” and add either “under normal conditions” or “maximum system conditions” so that it states “Perform a new short circuit study to determine the fault current values under normal conditions, not less than once every 24 months."
No
a) Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout this standard already address notification requirements. b) In R3,Part 3.3.1, change Requirement to read: “Changes are made to a Protection System as a result of findings during Misoperation investigations, commissioning, or maintenance activities.” (The current wording implies that all findings are due to errors. The reference to errors should be removed and the

emphasis of this Requirement needs to be placed on “changes” made to Protection Systems when it becomes apparent that a change is required which impacts coordination of relays.)
Yes
No
There may be instances where extenuating circumstances delay agreement beyond 90 days. For long lead time or complex protection scheme projects requiring more interaction between protective relaying engineers, exceeding the 90 day period could be acceptable to the entities involved. Evidence of mutual agreement on an extension beyond 90 days should be acceptable.
No
We recommend a consistent set of VSL timeframes across all requirements. The 10 day limits are unreasonable and, as stated in the R1.1.1 rationale, this urgency is not warranted. Most entities will have numerous Interconnection Facilities, so applying these VSLs to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: • Lower VSL should be 60 days late. • Moderate VSL should be more than 60 days, less than a year. • High VSL should be more than a year but done. • Severe VSL should be more than a year and not done.
a)Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1, Part 1.1.2 reads - “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.” For Requirement R1, Part 1.1.2, we recommend omitting the reference to R2 and reword so that the requirement is specific. Recommend changing to read: “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required”. b) The standard uses different formats for identifying deadlines. Sometimes “days” are used and sometime “months” are used. It is suggested that a common format be used. c) Please note that there appears to be an inconsistency in the 24 month requirement of R 2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual Requirements where time schedules are involved, the wording of the Requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the time schedule at the beginning of the Requirement whereas R1-1.2 references the time schedule at the end of the Requirement. Recommend using a standard wording format and list the time horizons in the beginning of the Requirement in all Requirements that have time requirements involved. For Requirement R1-1.2, we recommend changing to read: “Within 90 calendar days after the completion of the Protection System Study: Provide, to each affected Interconnected Facility owner, a summary of the results of each Protection System Study performed (including at a minimum the Protection System(s) reviewed and any proposed revisions).” e) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. i) The overall process would be less burdensome by changing R2, Part 2.1 to “not less than once every 5 calendar years” which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3. ii) The overall process would be less burdensome by deleting R3, Part 3.3 because such Protection System changes are already captured by R3, Parts 3.1 and 3.2. iii) Omitting ‘project schedule’ from R3 would streamline data exchange. f) Delete ‘operating’ from the Interconnected Facilities definition because “different functional or corporate entities” sufficiently captures all of them. We also suggest defining the singular Interconnection Facility, rather than the plural.
Group
GP Strategies

Mary Jo Cooper
Yes
Yes
We agree that there should be a process for ensuring that the industry continuously evaluates the system and ensures that the relay settings are coordinated and adjusted to meet the dynamically changing grid. However, we disagree that the studies should be conducted by the owners of the facilities. We feel these studied should be conducted by the Transmission Planner or Planning Authority and the cost of the studies should be allocated equally to all users of the grid. Currently, a study is performed when a new facility is added or an existing facility is modified. Typically, the study is conducted by the Transmission Planner as identified in FAC-002 and paid for by the facility that is being modified or is being added. It makes since that these facilities pay for the studies as they are the ones modifying the overall grid and benefit from the modification. In this case the cost should not be bared by an existing facility. The drafting team states that an owner should perform a study when the fault current changes by 10% or greater at their Interconnected Facility. The team may not have taken into account the potential that these changes are not related to that particular facility but rather from a change in the overall dynamics of the grid. For example, an influx of renewable resources (both behind and in front of the meters), retirement of generation, changes to transmission, or changes in load pockets. In addition, it excludes any new facilities added since 2007 from sharing the cost of changes to the grid. The cost for studies conducted for changes to the existing grid should be allocated to all interconnected facilities and should be performed by the Transmission Planner. As defined in the Rules of Procedure, section 500, the Transmission Planner is “the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area.” The Planning Authority is the entity that maintains the information required for the studies and is the entity that could perform the studies at the lowest cost. The cost for performing the studies should be allocated to all entitles doing business on the grid and the cost should be reviewed in a rate case and allocated appropriately. MOD-010 and MOD-012 already provides a requirement to provide the characteristics for system studies to the RRO for updating the models that would be used to conduct the studies. These Standards, however, have a gap in that they do not include Distribution Provider as indicated in the proposed PRC-027 Standard. We recommend the drafting team revise MOD-010 and MOD-012 to retrieve all necessary information to update the RRO model and that the Transmission Planner be tasked with performing the necessary studies.
Yes
Yes
Individual
Laura Lee
Duke Energy
Yes
No
Yes
However R1 is confusing by having two sub-requirements R1.1 and R1.2, two measures M1 and M2, and VSLs consisting of various combinations of non-compliance with sub-requirements. We think it could be made clearer by separating R1.2 out as a separate requirement with its own measure and

VSLs. We have made a similar comment on Question 8 that other requirements, measures and VSLs in this standard could be made clearer by breaking them apart. Also, Requirement R1.2 states “each affected Interconnected Facility owner” without describing how the owner may be affected.
Yes
However it’s unclear what Fault duty is being referred to. Is it the total Fault current at the bus, or Fault current that flows down the line or to the generator? It should also be clarified that Fault duty is the normal case (i.e. with all sources and all lines in-service).
No
Revise second bullet under R3.1 as follows: “Changes to line impedance”. Add another bullet under R3.1 as follows: “Changes to breaker failure scheme operating times”. Also, we don’t agree with the R3.1 Rationale that specifying a single time frame is inappropriate. A time frame similar to R3.2 should be specified. We suggest the following revised lead-in paragraph to R3.1: “According to an agreed-upon schedule or absent such an agreement, 180 calendar days prior to implementing any change or additions listed below; either at an Interconnected Facility or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities”.
Yes
We support the necessity for agreement, but there can be differences in philosophies that make reaching agreement difficult. How are disagreements to be handled? As the requirement is currently worded, the entity receiving the study has no alternative but to agree within the specified timeframes.
Yes
No
The requirements in this standard do not have solely one activity. Also, requirements R1, R2, and R4 do not have an activity or goal stated (other than is stated in the subparts). The requirements in this standard all have sub-requirements, multiple measures and VSLs consisting of various combinations of non-compliance with sub-requirements. We think the standard could be made clearer by separating sub-requirements out as separate requirements with their own measure and VSLs.
The order of the Requirements in PRC-027-1 should be put in chronological order to align with the Example Process outlined on page 22. PRC-001-1: It’s not clear that balloting for Project 2007-06 also includes PRC-001-3. General comment - The vague language of R1 does not make it practicable for the responsible entities to implement the requirement. The Purpose is limited to coordination/relationship with the applicable entities. The Purpose is vague as to whether it applies to the Bulk Electric System. Requirement R1 does not clearly state a reliability outcome/benefit. It is not aimed to achieve one objective. The phrase “shall be familiar with the purpose and limitations of protection system schemes,” is vague and not measurable. What does it mean to be “familiar” with in this context? Could this requirement be stated in a way that is measurable? The outcome is not obvious because of vague terminology. What will be the outcome of entities being “familiar purpose and limitations of protection system schemes?” The term “familiar” is too general to address a single activity. Although it can be inferred that familiarity with the purpose and limitations helps ensure reliability, what single reliability goal will be accomplished? There is no measure specified for R1 (according to the Model: each requirement must have one or more associate measures used to objectively evaluate compliance with the requirement). What type of evidence could be used so the entities are compliant with the requirement? The Data Retention language mirrors the recommended default language. However, because there are no measures, which are “used as a guide in identifying which responsible entity must keep the evidence and for how long,” where do the “3 years” come from? There is no supporting document or reference to a supporting document for justification of VRFs for PRC-001-3; although, there is one for PRC-027-1 (which does not mention PRC-001-3). No explanation is given for the “High” or “Severe” VRF for R1. Generally, how is the VSL said to be “Severe” if there are no measures for R1? Effective Date – There needs to be an explanation for the time lapse of more than 3 months between approval date and the effective date of the standard. Additional clarity is needed regarding performance requirements and how an entity would demonstrate compliance with R1. Requirement R1 doesn’t support the Purpose statement of the standard.
Group

Western Area Power Administration
Brandy A. Dunn
No
Don’t necessarily agree with the statement: “Protection Systems remove from service only those Elements required to isolate Faults..." This statement can be problematic since backup functions such as remote Zone 3 distance elements cannot be overlapped reliably yet are necessary for N-2 and beyond contingencies. Also, in some case it may be desirable to allow for intentional overlap or mis-coordination depending on the circumstances. These issues need to be resolved in the proposed standard or the standard eliminated.
No
No
No
We have concerns over what NERC considers to be a "Protection System Study". Needs to be defined more clearly.
No
What are the details to be provided? Should only be for significant changes.
No
See general comments below (#9).
General: Western disagrees with NERC standards becoming too specific on technical issues such as protective relay coordination. Protection Engineers are highly skilled and trained in system coordination and should be left to determine the proper course of action without the hindrance of PRC-027-1 requirements. There is a reason why, historically, protection system coordination has been termed "the Art and Science of Protective Relaying." The proposed standard also mentions that "Protection Systems remove from service only those Elements required to isolate Faults..." This statement can be problematic since backup functions such as remote Zone 3 distance elements cannot be overlapped reliably yet are necessary for N-2 and beyond contingencies. Also, in some case it may be desirable to allow for intentional overlap or mis-coordination depending on the circumstances. These issues need to be resolved in the proposed standard or the standard eliminated. Specific issues: - We have concerns over what NERC considers to be a "Protection System Study". Needs clearer definition. - Swap requirement positions R1 and R3. I.e. make R1 be R3 and R3 be R1. - R2.2: Provide equation. And, use “I” instead of “V” when referring to current. - R2.2: What values are being referred to for deviation calculation? (i.e. ground current, phase current, positive sequence, etc.) - R2.2: Clarify the fault current contribution or provide a table specifying the details - R3.1: Last bullet, suggest making the statement “Replacement of the transformer(s)” to cover all transformers. - R3.2: How does the neighboring entity know when to request? - R3: What are the details to be provided? Should only be for significant changes. - Concerned about dates and timelines associated with this standard. Often schedules and tasks change during design, checkout and commissioning. R1.1.3 and R3 need to be clarified. Western feels that this standard will create more questions than it answers. The standard, as written, is not clear or concise and would surely lead to CAN's and FAQ's.
Individual
Jack Stamper
Clark Public Utilities
Yes
No
Yes
Yes

Yes
No
The proposed Requirement R4 is not an acceptable method of confirming agreement among parties. Requirement 4.1 requires an entity to agree with the proposed changes within 90 calendar days. What if the entity thinks the proposed changes are wrong? Other standards that require entity A to provide information to entity B provide that entity B will provide written comments to entity A within a specified period of time. 4.1 should state the following: “Within 90 calendar days after receipt, provide written comments (if any) regarding the summary results of a Protection System Study, as described in Requirement R1, Part 1.2.” Requirement 4.2 will require an entity needing to implement a planned change to delay the in-service date until affected entities agree with the proposal. This sets up a potential stand-off with no method of resolution. In other standards where parties provide comments the entity is required to respond to those comments within a specified period of time. However, 4.2 as worded would stop the implementation until the other parties all agree. The owner of the facility needs to have ultimate and sole control for implementing these changes and the current 4.2 would stop a project dead in its tracks until the other parties all agreed. Proceeding without this agreement would result in a standard violation and imparts power upon entities over facilities they do not own. 4.2 should state the following: “Within 30 calendar days after receipt of any written comments received per Requirement 4.1 and prior to the in-service date of any planned change at the Interconnected Facility, respond to such written comments.”
Yes
Yes
Group
Associated Electric Cooperative, Inc., JRO00088
David Dockery
No
See comments posted by SERC PCS
No
Yes
AECI objects with the line of questioning here, because it does not fully address all aspects of Requirement R1. While AECI appreciates the 36 month time-frame, we did receive internal comment back from our planning engineers Relay Operations Sub-Committee: 1) Concerning our Regional Entity’s Short Circuit Data Working Group, the current status is such that a unilateral AECI SC study would be technically difficult. 2) Further, significant modeling development will be necessary in order for entities to comply with this requirement through a regional study formation, ie 3 yrs is a definite push on the timeline on the Initial pass. 3) Finally, the information to be reported from a Protection System Study R1.1, and particularly the information to be communicated to other entities R1.2, may be too vague. This primary concern is for personnel being inundated by the sheer volume of data that can now be performed in relation to such studies. AECI would appreciate the SDT providing further Industry Guidance as to what would constitute a clear and concise set of information, to be transmitted or received from corresponding parties.
Yes
A 10% threshold seems simple, but the SDT may or may not wish to clarify the formula to be applied because any of the following is a valid interpretation: 1) abs(Vscs – Vpss)/Vscs, 2) abs(Vscs – Vpss)/Vpss, 3) abs(Vscs – Vpss)/0.5(Vscs + Vpss), 4) abs(Vscs –Vpss)/Max(Vscs,Vpss), or 5) abs(Vscs-Vpss)/Min(Vscs,Vpss). Also see SERC PCS Comments.
No
AECI believes the industry would be better served by placing this list of items into a Guidance

document, and rephrasing R3 to include only “field-changes known to modify the conditions used in coordination settings of Protection Systems.” Although some of the listed items are direct-impact, as currently drafted, any field-equipment changes are potentially in scope, regardless of proximity to the Interconnected Facility(s) of interest. With exception of R3.1 Bullet #1, the R2.3 10% is a better metric and the other Guidance bullets and wording we proposed above, should be added into R2.3.
No
PRC-027-1 R4.2 change: Replace: “that Protection Systems(s) changes” With: “each related Protection Systems(s) change” Rationale: AECI sympathizes with the need for agreement, and believes that to be the necessary goal. However, this requirement indicates all-or-none for notified Protection System Change(s). Entities may agree on most all communicated changes, and yet a more complicated change, particularly outside of Zone 1, may require some interim compromise, or that one particular (backward-looking) be excluded until agreement is reached. Full agreement, prior to placing facilities into service, might otherwise become a method for forcing a poor compromise on protective settings.
Yes
These facilities take time and budget to build or implement, and so 3-months prior to field-changes seems reasonable.
No
See SERC PCS Comments.
See SERC Comments Also pertaining to PRC-027-1 Page 2, Terms:, "Interconnected Facilities" definition, proposed change: Replace: “functional, operating, or corporate entities” With: “functional or operating entities” Rationale: In certain cases, independent Corporate entity is irrelevant to the planning and operations of these systems. As written, the underlying 6 G&Ts of AECI’s JRO could technically and unnecessarily be subjected to this standard for AECI's internal Facilities, and not just Interconnected Facilities between AECI and other non-JRO entities, although AECI's JROs functionally coordinate relay settings much as a large IOU’s regional departments would.
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
No
Please strike “while meeting the system performance specified within requirements established in other approved NERC reliability standards.” It provides no additional explanation for the purpose and these “other approved NERC reliability standards” apply regardless of this standard. In generally, it is not necessary to reference other NERC standards within a standard and, in fact, should be avoided as a standard should stand alone.
Yes
No
(1) Conceptually, we agree with the intent of the standard and this requirement as it is presented in the application guidelines. However, more refinement is needed to make this requirement implement what is explained in the application guidelines. For instance, nowhere in Requirement R1 is it stated clearly that the responsible entity is only responsible for performing Protection System Studies (PSS) for only those breakers it owns and are protecting the Interconnection Facility. This is pretty clear in the application guidelines. (2) While we do not disagree with the time frame, we question if it should be part of the requirement. It makes more sense to include the time frame for initial compliance of a requirement in the implementation plan. In that way, the initial compliance time frame does not persist in the standard long after it is no longer needed. It is common to utilize the implementation plan to describe initial compliance dates. Furthermore, FERC approves implementation plans as part of the standards package so there is no issue with whether the implementation plan are enforceable. (3) We disagree with limiting PSS that can meet this requirement to only those that occurred after June 18, 2007 as defined in Part 1.1.1. While NERC cannot compel evidence from a date before the standards became enforceable, there is no reason that a TO, GO, or DP could not choose to utilize a PSS from before this date as evidence. (4) We think the use of PSS in Part. 1.1 is partly redundant to the definition. The definition indicates PSS is a study that demonstrates Protection Systems operate in desired sequence for clearing Faults. Part 1.1 states that the TO, GO, and DP shall perform the PSS

“to verify Protection Systems remove from service only those Elements required to isolate Faults” are removed from service. Isn’t the statement in Part 1.1 “to verify Protection Systems remove from service only those Elements required to isolate Faults” equivalent to the demonstrating that Protection Systems operate in the desired sequence for clearing faults as defined in the PSS? (5) We disagree with including the Distribution Provider in this requirement. The primary reason that a Distribution Provider owns Protection Systems that protect Interconnected Facilities is that it is often cheaper to install a fault interrupting device and its associated Protection Systems on the distribution side. These Protection Systems are typically installed per the Transmission Owner facility connection requirements which are established per FAC-001. The Transmission Owner usually still performs the PSS and short circuit study and the Distribution Provider uses settings specified by the Transmission Owner. The fact that FAC-001 applies only to the TO and allows the TO establish such facility connection requirements that applies to the DP further supports this claim. (6) The definition of Interconnection Facility is confusing and needs further refinement. First, we are not sure what the purpose of including “that are electrically joined by one or more Element(s)” is. If it is not electrically joined, it cannot be a Facility. It would not be part of the BES which is a basic requirement of the Facility definition. Second, it is not clear if this is intended to cover only jointly owned Facilities or not. We do not think that is the intention but the clause “are owned by different functional, operating or corporate entities” cause this confuses. Third, ownership cannot be defined by functional or operating entities. A corporate entity may be registered as a TO and GO. Which part of the definition applies for the interconnection between the transmission system and generator: Functional Entities or Corporate Entities? Furthermore, a functional entity or operating entity does not really describe a legal entity capable of ownership. The definition of Interconnected Facility should be a Facility that ties together two different sets of Facilities together where the Protection System coordination would be performed by different companies. This would appear to be consistent with the explanation of the standards in the application guidelines. For example, a Facility connecting two different TO transmission systems together where the TOs are owned by separate corporate entities would be an Interconnected Facility. A generation interconnection Facility would only be considered an Interconnection Facility if the GO and TO were separate corporate entities. If they were the same corporate entity, coordination would already occur and the generation interconnection Facility should not be considered an Interconnected Facility.
No
(1) While we do not have an issue with the +/- 10% Fault current threshold, we question if the TO should be responsible for calculating the percent deviation for all Protection Systems for all Interconnected Facilities. Rather the TO should be responsible for calculating Fault currents on its transmission system and should be required to calculate the percent deviation for only those breakers and associated Protection Systems it owns and are protecting an Interconnected Facility and that it has performed the Protection System Study (PSS). The TO should communicate the Fault current to the owners of other Protection Systems protecting the Interconnected Facilities for them to calculate the percent deviation. (2) The main part of the requirement needs to be modified to further clarify for which Interconnected Facilities the TO is conducting short studies. As it is written now, each TO has to perform these short circuit studies for each Interconnected Facility. This literally means a TO has to perform short circuit studies for Interconnected Facilities for which it has no information or is even remotely responsible. For example, a literal reading would mean a TO in the Eastern Interconnection would have to perform a short circuit study for an Interconnected Facility in the Western Interconnection. Obviously, this is not the drafting team’s intention but the language does need refinement.
No
(1) In general, we are supportive of the list and requirement because it helps to clarify what changes are intended in Part 1.1.3 in Requirement R1. However, we have identified two specific issues with the list. First, we question if this requirement is at least partly duplicative with FAC-001-0 R2.1.2 which requires the TO to have procedures for notification of new or modified equipment. Second, the third bullet regarding additions, removals, and replacements of transmission system Elements is too broad. This literally means that if a TO replaces a bus section with similar equipment, this requirement to notify of changes is triggered which then triggers a Protection System Study or documentation that one is not required per Requirement R1 Part 1.1.3. Ultimately, we believe the changes that need to be identified are those that actually affect the Protection Systems for the Interconnected Facilities or those that change the Fault current on the Interconnected Facilities. (2)

The 30 day requirement should be struck from Part 3.2. If a schedule is not identified by any party, it must not be pressing and an artificial deadline should not be created. (3) The language of the main requirement needs to be further refined. A literal reading would require the TO, GO, and DP to provide details about Interconnected Facilities that they neither own nor operate or to which they are even connected. Obviously, the literal meaning is not intended. The requirement needs to be refined to clarify that the TO, GO, and DP only need to provide the details for Facilities they own. (4) For Part 3.3.2, we suggest clarifying that this requirement does not apply if the equipment is replaced with like equipment and settings. We also suggest that that some sort of exemption is written into this part for extreme weather events that allows more time for notifications.
Yes
Yes, we agree. The application guidelines were particularly helpful in explaining how the Requirements R3 and R4 work together.
No
We assume this question refers to Part 4.1. While we do not see any issues with the 90 day requirement, Part 4.1 needs to be modified to reflect what a responsible entity must do if they do not agree. As written any other response than agreement is a violation. Thus, if a TO indicates it disagrees with the results of the Protection System Study (PSS) within 90 days, it technically is in violation of the requirement. The application guidelines explain that absent agreement the revisions should be proposed. We agree with this approach but the requirement simply does not say this. It should.
No
(1) The time horizon for R2 should only be Long-term Planning. The study has to be completed every 24 months and while notification in Part 2.3 has to occur within 30 days it is only after that the study to satisfy the 24 month time period is complete. (2) Requirement R3 should include Long-term Planning. Transmission system expansions would be covered under Part 3.1. (3) The VSLs for Requirement R1 are gradated based on the number of days late the requirement is met for Part 1.1 but not Part 1.2. It seems Part 1.2 should have similar gradated VSLs. (4) For Requirement R4, we suggest the VSL for Part 4.2 should clearly state that any changes made during extreme operating circumstances (i.e. extreme weather) are excluded. This is essentially a question on what is meant by “planned”. Are changes made to restore service in a hurricane or tornado damaged area a few days after the devastation planned? We think they are not but see how auditors could view the changes as planned particular if any level of study was required.
(1) Please restate section 4.2. It states that it applies to Protection Systems installed at Interconnected Facilities. “Installed at” is not really the intention. It should be Protection Systems installed to protect Interconnected Facilities. While they most likely would be at the Facility, they do not have to be. For example, a 500 kV transmission line is a Facility. Protection Systems will not be “Installed at” the line but rather at the substations. (2) If PRC-001-3 R1 is going to be retained, it needs to be further refined. First, it inappropriately uses the term area when referring to a GOP. While the BA and TOP do have Balancing Authority Areas and Transmission Operator Areas, no equivalent exists with the GOP. The GOP simply operates generating units not areas. Second, the requirement confuses the role of the GO and GOP. In the functional model, it is the GO that is responsible for installing, setting and coordinating generation protection systems not the GOP. Thus, it is not clear what role the drafting team envisions for the GOP being familiar” with the purpose and limitation of protection system schemes applied in its area”. Third, the requirement is written too broadly for the BA. Because the requirement compels the BA to be familiar “with the purpose and limitation of protection system schemes applied in its area” this could literally require the BA to understand many protection schemes for which it has no direct or even indirect responsibility. For instance, distance and differential protection schemes are contained within the metered boundaries of a BA Area. This requirement would compel the BA to be familiar with them even though this knowledge would have zero impact on its decision making or responsibilities. This does not align with the responsibilities assigned to the BA in the functional model. The BA being included in this requirement is likely a vestige of the version 0 standards and should be corrected. When version 0 standards were translated from the policies, BA and TOP were simply substituted for control area regardless of the role the control area was playing in the requirement. (3) The NERC function model defines one role of the Transmission Planner as “define system protection and control needs”. Should the Transmission Planner have a role in this standard? For instance, should the TP actually perform the short circuit studies? (4) The application guidelines and examples are very helpful in understanding the intent of

the drafting team. However, we recommend revising the example regarding Figure 3. It would appear to assume a distribution level generator is part of the BES and subject to NERC standards. While it is possible for a generator on the distribution system to be part of the BES (i.e. if it is a Blackstart Resource), inclusion of such a generator would be unusual and an exception to the normal BES 100 kV threshold. If the generator is not part of the BES, there would be no Generation Owner registered to perform the coordination. Industry is likely to be sensitive to such an example. Removing the generator will still allow the example to communicate that a breaker and associated Protection System on the high side (100 kV or higher) of a distribution or step-down transformer would still have to be coordinated.
Individual
Eric Salsbury
Consumers Energy
We feel that this is a very difficult standard to interpret consistently as written. We think a negative vote is warranted since it is confusing and unclear for our situation. Following are specific comments to support our negative vote. In regard to the Process Flow Chart on page 21 - We assume this Process Flow Chart is intended as an illustrative clarification of the standard, not a supplement to the wording. The chart claims to be a “complete representation of the process” and as such should match identically or it should be eliminated as it causes confusion. It is our interpretation that the chart does not match the standard’s wording. One example if you start with an R3 emergency replacement you end up with two conflicting results. Under 4.3.2 you have 30 days to confirm that the changes are acceptable. Under 1.1.3 you have to do a protection study so you are given 90 days per section 1.2. This entire chart should be verified to ensure that it matches the written standard and does not result in conflicting requirements. We suggest adding the sub-requirement labels to each flow chart item for easier reference to that section of the standard. In regard to Figure 3 on page 25 - The figure appears to represent the connection of a large NERC qualified generator. Does this figure also apply to a looped source distribution system or should that follow figure 4? We would like to see a definitive example that clarifies what to do for the situation where you have a looped source distribution system. In regard to Figure 4 on page 26 - the figure implies that A & B can be set to overtrip C (as no study is required) which would interrupt the BES for distribution faults. This appears to be contrary to what is intended by this standard.
Individual
Brian J Murphy
NextEra Energy Inc
Yes
No
While 36 months is allowed for studying all interconnections, what time is allowed for mitigation of identified setting or hardware change? If an issue is discovered, then an additional 12-24 months mitigation time should be allowed.
No
It would seem that NERC Standards efforts, such as PRC-027 should focus on areas that have a record of poor performance and a contributor to misoperations. The area of tie line protection addressed in PRC-027 is not an area of poor performance, see page 4 of the attachment “….Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard

PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations". Areas that are less problematic should be addressed by NERC with less intrusive methods such as Industry Alerts, general cautionary statements or a standard with less detailed documentation requirements. Thus, PRC-027, as drafted, will unnecessarily require additional focus and resources be placed in an area that has not been a problem for the reliability of the BES. Alternatively, PRC-027 should be drafted much less prescriptively from a technical standpoint, and allow for more discretion on how to conduct the study and how to coordinate the results. The prescriptive nature of many of the technical requirements PRC-027 is so narrow that it may counterproductive. A results-based approach here should focus more on conduct a study and coordinating the results, rather than dictating how the technical requirements of how study is to be completed.
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
No
Oncor takes the position that the word "only" in the Purpose is too subjective and allows for multiple interpretations. Oncor believes that in order to provide clarity, Oncor suggest that the Purpose be modified as follows: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.
No
No
Given the "agreement" requirements defined in Requirement R4 and the uncertainty of its interpretation, many of the recent protection system studies may have to be performed again. Therefore, a more appropriate timeframe would be 5 years to have all applicable Protection System Studies completed.
Yes
Oncor takes the position that the 10% fault current threshold criteria is the only criteria needed;
Yes
No
Oncor believes agreements must be reached; however, there needs to be some definitions in the Standard to define the exact meaning of the term "agreement". In addition, the sub requirements 4.3.1 and 4.3.2 calls for confirmation of the Protection System changes are acceptable pursuant to notification received in Requirement 3, within 30 days, however the sub requirements provide no mechanism for resolution in the event the changes are not acceptable to the receiving entity within 30 days of receipt. Oncor suggest that these two sub requirements be removed. There is sufficient checks and balances under 4.2 to provide coverage for any disagreement between entities without the need to self-report under the 4.3.1 and 4.3.2 if an agreement cannot be reached within 30 days of receipt.
Yes
No
Until 'agreement' definitions or further clarity as to what is an "agreement", can be added the Standard, Oncor does not believe that VRFs and VSLs can be established for this standard.
Based on a thorough review of the proposed Standard, Oncor has identified several questions or

comments which need to be addressed in the Standard to ensure the Requirements are clear. • R4.1: please provide clarification of which entity would be out of compliance if the 90 day requirement is not met - initiating entity or receiving entity or both • M9: What does "confirmation" mean as explained in Measure M9? • R4: please incorporate a definition of “agreement” • R4.2: please incorporate some examples for "evidence of agreement"? o There are two types of agreement that are needed; the first being an "agreement" with the overall projected relaying scheme (i.e. agreement with preliminary conceptual design detailing proposed protection scheme changes). This is prior to any equipment being purchased. The second agreement, which could be identified as more of a concurrence, is agreement that both relay systems coordinate from a protection standpoint (i.e. concurrence with relay setting changes). The relay setting process and concurrences occur later in the project closer to the in-service dates. In addition, the sub requirements 4.3.1 and 4.3.2 calls for confirmation of the Protection System changes are acceptable pursuant to notification received in Requirement 3, within 30 days, however the sub requirements provide no mechanism for resolution in the event the changes are not acceptable to the receiving entity within 30 days of receipt. Oncor suggest that these two sub requirements be removed. There is sufficient checks and balances under 4.2 to provide coverage for any disagreement between entities without the need to self-report under the 4.3.1 and 4.3.2 if an agreement cannot be reached within 30 days of receipt. • R3.1: please provide further clarification of the statement "modifies the conditions used". It would seem that most system changes would modify the conditions used even though for many of those changes, coordination would not be impacted. Oncor takes the position that the phrase provides ambiguity and subjectivity that would difficult to measure or audit.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
No
Yes
Yes
No
R3.3 in its entirety should be removed considering that all conditions covered by R3.3 are already covered by R3.1 which states: “New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios” If a correction or replacement of a protection system element is made per R3.3, this is the same thing as a modification covered under R3.1. It is noted that R4 would need to be reworded to accommodate unplanned and emergency protection system changes.
Yes
Yes
R4.1 only mentions R1. R4.2 should be reworded to make it clear that entities have 90 days to respond to proposed protection system changes received per R3.1. The concern is that with no specified time the responding entity can delay the initiating entity’s schedule even if the protection system changes were shared well in advance of the in service date.
Yes
Group
Kansas City Power & Light
Tim Hinken
No

The reliability objective of this standard should be to insure that there is an agreement between two interconnected entities of relay protection schemes and relay protection settings for the interconnected facilities. This is achieved if there is documentation stating that the Interconnected operating companies have reached agreement on protection schemes and protective relay settings. This standard should only require documentation that neighboring owners are talking and agreeing with one another in relation to protection and control. The present purpose makes it appear that you are in violation of the standard any time the system has a misoperation because of relay setting regardless of whether both parties have agreed on the settings used but the measures tend to measure agreement with the other entity. This is the reason that the present purpose needs to be rewritten the auditors may interpret the purpose to indicate any misoperation due to setting issues is a violation.
No
The applicability should also include Transmission Operators and Generator Operators as it is possible for jointly held facilities to be owned by several parties and operated by another party and relay protection responsibilities could be with the Operator of the facility. It should be clarified the proposed Standard is applicable to Distribution Providers that provide protection for BES Elements.
No
The protective systems were coordinated when installed. If the power system has not undergone any significant change, then line impedances and fault current levels are the same and the original settings are still valid. So, no new study is required based on the passage of time. A new study is needed only if there have been significant system changes as outlined under question 5 and requirement R3. Requirement 1.1 states each entity must perform a system protection coordination study, however, the coordination efforts will be joint efforts between the entities and sharing of pertinent information such that an effective study can be performed. The proposed Standard should make it clear the study effort can be a joint study between the entities involved and that independent studies are not necessarily intended by each entity.
No
Primary protection of most transmission lines is impedance based. Sensitive ground over current systems are used for communications assisted tripping and time ground over current systems are typically used as backup protection. Some line protection is differential based. Some entities also apply instantaneous ground over current relaying for faults at some fraction of the protected line. Increases in fault current do not affect impedance based relaying. Communications assisted sensitive ground elements are set well below available fault current levels and increases in fault current levels will not hinder proper operation. Differential based systems would also not be harmed by fault current increases unless fault currents increase enough to result in ct saturation. Since time ground over current relays are usually used as backup protection they are typically set only to operate if the primary relaying protection has failed. These relays are typically set to coordinate based on time delays for ground faults on the protected line. Because the overcurrent curves are based on a log scale the increase in current magnitude does not correlate to the same percentage in time. Instantaneous ground over current elements are most susceptible to misoperations caused by increases in fault current, however these elements should be initially set to protect only the first 50 to 70% of the protected line based on the fault current at the remote end. With this in mind a fault current increase of 10% is not significant by itself to require a setting review and it is very difficult to see how a 10% decrease can affect the coordination unless over current elements are the primary protection elements or over currents elements can prevent the operation of the other protection functions. If the SDT is adamant about having a periodic review of fault current levels then the time should be extended to 5 years and the fault current level should be increased to 20% on the protected line.
No
Bullet item #3 is too broad. The NERC Glossary definition for Element is, “Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.”. For example, a disconnect switch would be considered an Element, but a change of this component would not warrant a change to relay protection. Recommend modifying bullet item #3 to, “Additions, removals, or replacements of transmission system Element(s) that have an impact on relay protection systems or component(s)”

Yes
No
These can be matters of extreme complexity in design, implementation and operation. Stipulating that 90 days (Requirement 4.1) and 30 days (Requirement 4.3) is sufficient time to come to an agreement is presumptuous and is not necessary. Requirements 4.1 and 4.3 should stipulate that entities in receipt of proposed changes to relay protection system(s) or component(s) be evaluated and responded to by the entity in receipt. The response could be agreement or non-agreement with concerns or objections noted in the response.
No
The 10 day increments represent a 5% error and considering this is a six month requirement. The 10 day increment represents 4 – 6 working days across 2 weekends and including a holiday. Recommend the increments be increased to allow at least 10 working days which would be at least 15 calendar day increments. VSL for R2, part 2.1 – The 10 day increments represent a 1% error and considering this is a 24 month requirement. Recommend the increments be increased to 30 days to make more sense with the 24 month period.
Requirement 1.1 of R1 states, “Perform a Protection System Study for each Interconnected Facility to verify that Protection Systems remove from service only those Elements required to isolate Faults as follows:”. The purpose of this standard should not be to remove from service only those Elements required to isolate Faults, therefore 1.1 above should state, “Perform a Protection System Study for each Interconnected Facility as follows:”. Requirement 1.1.2 of R1 states, “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.” Since this Requirement is an action as a result of requirement R2 and as noted in the response to question 6 above, R2 should be deleted. If the SDT is adamant about having a periodic review of fault current levels then the fault current level should be increased to 20% on the protected line. A 10% fault current change is not significant enough to require a new protection system study. Requirements R4.3 and R3.3 are actions as a result of a misoperation and because there is already a standard (PRC-004) that deals with misoperations these two requirements should not be covered in this standard if changes need to be made due to misoperations they should be made in the misoperation standard (PRC-004). This standard is not intended to replace the Misoperation Standard and any requirements addressing misoperations gives FERC, NERC and the Audit Teams the wrong impression of the intent of this standard. All Protection System Studies are dependent on accurate system models. Individual Entities should not be responsible for development and maintenance of an accurate Regional model or model to be used between Regions. Individual Entities should only be responsible for providing the information on their system to the Regional Entity so that an accurate model can be maintained by the RC. I propose that this standard be applicable to the Region and require the Region to maintain an accurate model that includes zero sequence impedance and is useful for Protection System Studies. This system model also needs to be accurate between Regions for Protection System Studies that span between Regions. This will require that the standard also be applicable to NERC RRO and require RRO to oversee the process of maintaining an accurate national model or equivalents that can be used between Regions. Anything less than this is placing an unfair burden and unrealistic expectation on the TO to produce and maintain an accurate model for interconnecting Protection System Studies. A dispute resolution mechanism also needs to be required to provide for instances where entities cannot come to a mutual agreement. Recommend a requirement be included for entities to request applicable RC(s) to arbitrate to bring resolution to a matter.
Individual
Jian Zhang
TransAlta Centralia Generation LLC
No
The Interconnected Facilities definition is not clear.
Yes
The applicability should include other functional entities which should provide power system study data.

1) Applicability 4.2 Facilities should be Protection System installed at Interconnected Facilities that required coordination. 2) R2- For the Inteconnected Facilies only for the purpose of the generator interconnection, only the Transmission Owner providing the generator interconnection should be required to perform the tasks as mentioned in R2, not the other entity (generator) even though it is registered as the Transmssion Owner. 3) R2 2.1 perform a short circuit study to determine the present fault current values, not less than once every 24 months. 24 months is too often. Suggest to change to “once every 60 months unless there is major equipment change on the system”.
Individual
Pablo Oñate
El Paso Electric
Yes
No
Yes
It is unclear whether the proposed standard intends to reach 10% or greater deviations that accumulate over the course of a more extended period of time (i.e., greater than 2 years), or whether an entity can seek to perform multiple studies within a compressed period of time in such a way that it can ensure that a 10% deviation will not be reached from study to study, as illustrated below: • Study performed in Year 1 shows a 5% deviation • Study performed 12 months later (in Year 2) shows a 5% deviation • Study performed 12 months later (in Year 3) shows a 5% deviation [Cumulative deviation of 15% within 3 years, but only a 5% deviation from study to study]
Yes
Yes
No
EPE believes the timelines are not adequate when coordinating protection system studies involving sequential interdependence among parties for interconnected facilities . Timing of study data should correlate with any written agreements or procedures agreed to between the various parties. EPE also believes the documentation requirements within this draft Standard slow down the process, therefore increasing the time needed to complete and communicate the study data. The proposed Standard fails to address two important and likely types of situations: (a) the situation in which an interconnected entity fails to respond with study results or to a planned change at the Interconnected Facility, or (b) the situation in which disagreements between the entities are not resolved within the proposed Standard’s time clock.

Additional Comments Received:

Dominion Resources Services, Inc.
Mike Garton

Question 1

In the current PRC-001-1 standard the meaning of the term “coordination” has and still is interpreted in two ways. One interpretation is viewed from the technical aspect as “relay coordination” and the second is viewed from an inter-communication aspect as “coordination of information” between entities. The term “coordination” should be removed from the new standard Title and Purpose. Recommend changing **Title** to: “Protection System Interconnected Facility Performance During Faults”. Also, recommended is to change the **Purpose** to read: “To communicate and exchange Protection System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those Elements required to isolate Faults.” In PRC- 027-1, use the term coordination only when referring to the technical aspects of the relay coordination within a Requirement when applicable.

Under **Purpose**, delete: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet ‘the system performance specified within requirements established in other approved NERC Reliability Standards’ and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1.

Question 4

a). In R2-2.2 Replace the term “deviation” with “change”. {(Note: For this calculation all that is required is to calculate percent change. i.e. Webster’s dictionary definition of “deviation” is 1) A variation that deviates from the standard or norm; "the deviation from the mean”. 2. The difference between an observed value and the expected value of a variable or function. This is not a statistical calculation.) }

b). In R2-2.2, Replace the term “present” with “new” and the term “most recent” with “previous”.

c). Change the % Deviation Equation to % Change. Reflect as stated above in the equation legend (the use of the terms “present” and “most recent” can be perceived to be the same).

d) Replace “V” (Value) with “I” (Current) in the % Change Equation. “V” is frequently used to represent Voltage and this could lead to confusion.

e). In M5 Replace the term “deviation” with “change”

f). In R2-2.1 please add “new”, delete “present” and add either “under normal conditions” or “maximum system conditions” so that it

states “Perform a *new* short circuit study to determine the Fault current values *under normal conditions*, not less than once every

24 months.

Question 5 (NO)

a). Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout the draft already address notification requirements. By using the term project scheduling this implies that detailed project information needs to be included in the information exchange. The standard should not dictate the information exchange details required and should allow the entities to determine what information is required in the exchange in order to achieve protection coordination in the appropriate timeframe.

b). In R3 reword to read: <u>"Each Functional Entity shall provide to other Functional Entities connected to an Interconnected Facility, the details of the Protection System as follows:" (It</u> is not necessary to include (e.g. Examples) since references to these are already listed in R3-3.1.)

c). In R3-3.1 reword to read: <u>"When adding new or modifying existing Interconnected Facilities or when making changes to other facilities where the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities"</u>

d). Bullets: 1st bullet -Recommend changing reference to "protective Function settings" to <u>"protection settings"./</u> 2nd bullet – Reword to read: <u>"Line impedance changes" /</u> 3rd bullet – Remove the word "system"

e). In R3-3.3.1 change Requirement to read: "Changes found during Misoperation, commissioning, or maintenance activities

that modify the conditions used in the coordination of Protection Systems. "

Question 7

Reword R4., 4.3 to read: <u>"Within 30 calendar days after receiving notification of:"</u>

Question 8 (NO)

a). Dominion recommends a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale this urgency is not warranted. Most entities will have numerous Interconnection Facilities so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general:

- Lower VSL should be 30 days late.
- Moderate VSL should be more than 30 days, less than a year.
- High VSL should be more than a year but done.
- Severe VSL should be more than a year and not done.

Question 9

a). Dominion is concerned that a YES vote will also endorse the revision, also part of this project, to PRC-001-3, would then be reduced to only one requirement that is not measurable and does not contribute to the purpose of the standard. The Measure for the requirement has also been removed. The PRC-001 standard should be retired or mapped to another standard.

b). The proposed definition of Protection System Study is vague and introduces subjective terms such as “demonstrates” and “desired sequences”. Recommend the following definition: “<u>A study that determines the proper selection of settings for existing or proposed protective relays in order to properly isolate Elements.”</u>

c). Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1-1.1.2 reads - **“Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.”** For Requirement R1-1.1.2 - Omit the reference to R2 and reword so that the requirement is specific. Recommend changing to read: <u>“Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required”</u>.

- Change R1-1.1.3 wording to read <u>“When proposing or being notified of a change that modifies the conditions used in the coordination of Protection Systems at the Interconnected Facility unless the entity can demonstrate such a study is not required.”</u>
- R2-2.2, delete reference to R2. Delete “pursuant to Requirement R2, 2.1”.
- Change R4-4.1 to read: <u>“Within 90 calendar days of receiving summary results of a new Protection System Study, confirm agreement with the summary results.”</u>
- Change R4-4.2 to read: <u>“Prior to the installation of a proposed change that modifies the existing conditions used in the coordination of Protection Systems of the Interconnected Facilities, confirm the affected Interconnected Facility owner(s) agree with the Protection System(s) change.”</u>
- Change R4-4.3.1 to read: <u>“Changes made to a Protection System as a result of findings during Misoperation investigations, commissioning, or maintenance activities, confirm the Protection System(s) changes are acceptable.”</u>
- Change R4-4.3.2 to read: <u>“Emergency replacements are made due to failures of Protection System components confirm the Protection System(s) changes are acceptable.”</u>

d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual Requirements where time schedules are involved, the wording of the Requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the time schedule at the beginning of the Requirement whereas R1-1.2 references the time schedule at the end of the Requirement. Recommend using a standard wording format and list the time horizons in the beginning of the Requirement in all Requirements that have time requirements involved. For Requirement R1-1.2, Change wording to read: **<u>"Within 90 calendar days after the completion of the Protection System Study, provide to each affected Interconnected Facility owner a summary of the results of each Protection System Study performed (including at a minimum the Protection System(s) reviewed and any proposed revisions)."</u>**

- Change R2- 2.3 wording to read: <u>Within 30 calendar days after identifying that the calculation performed between the previous Protection System Study and the new study indicates a change in Fault current of 10% or greater, notify each Interconnected Facility owner, at which the 10% or greater change applies.</u>
- Chang R3-3.2 wording to read: <u>"Within 30 calendar days of receiving a request for information in the absence of an agreed-upon schedule or according to an agreed-upon schedule with a Transmission Owner, Generator Owner, or Distribution Provider."</u>

e). Throughout this 1st draft of the standard, there are references that illustrate documentation requirements that are inconsistent. <u>Recommend all be written as "(hard copy or electronic file formats)".</u>

f). Please note that there appears to be an inconsistency in the 24 month requirement of R 2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime.

g). There are several requirements stipulated throughout the draft standard creating the concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process.

1). The overall process would be less burdensome by changing the R2 2.1 to "not less than once every 5 calendar years" which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3.

2). The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2.

3). Omitting 'project schedule' from R3 would streamline data exchange.

h). There is confusion on the connections at the end of the flow chart. Please provide clarification.

END

Consideration of Comments

Project 2007-06 System Protection Coordination

The System Protection Coordination Drafting Team thanks all commenter's who submitted comments on the 1st draft of the standard for Protection System Coordination for Performance During Faults. These standards were posted for a 45-day public comment period from May 21, 2012 through July 5, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 76 sets of comments, including comments from approximately 198 different people from approximately 139 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/System_Protection_Project_2007-06.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received

Definitions

The drafting team added the following sentence to the standard to specify that the definitions will not be added to the NERC Glossary of Terms. "The following terms are defined for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the Glossary of Terms:"

The drafting team modified the previous definition of Interconnected Facilities to 'Interconnected Element' defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity."

Purpose

The drafting team modified the purpose statement based on comments related to two main issues: (1) the inclusion of the phrase '…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards', and (2) the inclusion of the phrase '… remove

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

from service only those Elements...'. The purpose now reads: To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.

Applicability

The Applicability was modified as follows:

4.2 Facilities: Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.

Requirements

The time frame for Requirement R1, Part 1.1.1 was increased to forty-eight calendar months to allow entities with large numbers of Interconnected Elements enough time to complete the Protection System Studies. Additionally, changes were made to not exclude studies performed prior to June 18, 2007. Requirement R1, Part 1.1.1 now reads: (Part 1.1 Perform a Protection System Study)…"Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists."

The drafting team modified Requirement R1, Part 1.1.2 to be consistent with the Fault location referenced in Requirement R2, Parts 2.1 and 2.2 such that it now reads: "Within six calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required."

The drafting team modified Requirement R1, Part 1.1.3 for clarity. It now reads: "According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 or Part 3.3, or technically justify why such a study is not required."

The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."

The drafting team reworded Requirement R2 to read as follows: "For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall:"

The drafting team modified Requirement R2, Part 2.1 to provide clarity as to where the Fault should be applied. Requirement R2, Part 2.1.1 now reads: At least once every 24 months: "Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."

The equation stated in Requirement R2, Part 2.1.2 was modified to replace "V" with "I".

The drafting team modified Requirement R2, Part 2.2 to provide clarity and to change "notify" to "provide" such that it now reads: "Within 30 calendar days after identification where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates a deviation in Fault current of 10% or greater, provide each owner of the Protection System associated with the Interconnected Element the updated Fault current values (Iscs)."

The drafting team modified Requirement R3 for clarity and moved the examples into Measure M5 such that it now reads: "Acceptable evidence may include, but is not limited, a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) in hard copy or electronic file formats as identified in the bulleted list for Requirement R3, Part 3.1 was provided to each responsible entity connected to the same Interconnected Element."

The drafting team modified Requirement R3, Part 3.1 for consistency with changes to other requirements, the addition of the examples, combining the second and third bullets, and clarity. It now reads: "Details for any change or additions listed below; either at an existing or new Facility associated with the Interconnected Element; or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).

- New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios
- Changes to a transmission system Element that change any sequence or mutual coupling impedance
- Changes to generator unit(s) that result in a change in impedance
- Changes to the generator step-up transformer(s) that result in a change in impedance

The drafting team modified Requirement R3, Part 3.2 for clarity. It now reads: "Requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 calendar days of receiving a request or according to an agreed-upon schedule."

The drafting team combined the Requirement R3 Part 3.3 subparts 3.3.1 and 3.3.2 into the main body of the Requirement R3, part 3.3 which now reads: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."

The drafting team removed the term “confirm agreement” from Requirement R4, Part 4.1 and revised it to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”

The drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”

The drafting team removed Requirement R4, Part 4.3.

Measures

The drafting team modified all the measures to be consistent with the revised requirements.

Evidence Retention

The drafting team modified the language for consistency.

VSLs and Time Horizon

The drafting team made no changes to the VRFs; however, the following changes were made to the VSLs:

- For Requirement R1, Part 1.1.2, the time period for tardiness in the ‘Lower’ VSL was lengthened from 10 days to 30 days.

The drafting team added Long-term Planning to the Time Horizon for Requirement R3.

Guidelines and Technical Basis

Complementary changes were made to the Guidelines and Technical Basis corresponding to all changes to the standard.

The drafting team added the following to the description of a Protection System Study in the “Guidelines and Technical Basis”: “System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions.”

The drafting team revised the description relating to Figure 3 in the “Guidelines and Technical Basis” to clarify that only the Distribution Provider’s Protection Systems installed to protect for Faults on Transmission System Elements are a part of the Applicability of this standard. The drafting team modified Figure 3 to indicate that the source could be a generator or a network system.

The drafting team modified the text associated with each Figure to identify the Interconnected Elements.

The drafting team modified the process flow chart to be consistent with the requirements.

Unresolved Minority Views

- Several commenters felt that the Transmission Planner, Planning Authority, Transmission Operator and/or Generator Operator should be included because those entities were identified as providing the Protection System Studies and/or system modeling services for the owners. An example response to these comments was as follows: The SDT believes that the owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others.
- Several commenters disagreed with the Distribution Provider being included. The SDT responses indicated that the inclusion of Distribution Providers was appropriate if the Distribution Provider owned Protection Systems that require coordination with other owners for isolating generation and Transmission Faults.
- A few commenters disagreed with the 10% deviation trigger. The drafting team recognizes there are variations of margins used throughout the industry; however, believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.
- A few commenters had concerns with the 30-day time frame in Parts 3.2 and 3.3 while other commenters wanted them eliminated. The drafting team explained that they believed the 30-day time frame is appropriate and declined to make the change.
- Some commenters wanted to remove reference to schedules in the requirements. The drafting team reinforced that they believe the sharing of project schedules is a necessary communication between entities.
- A few commenters expressed concerns that there is redundancy between this draft standard and several FAC standards. The drafting team stated their belief that these concerns were not applicable.
- Several commenters expressed a desire to see the standard drafting team develop and include a conflict resolution process for situations where mutual agreement cannot be reached. The drafting team responded with the following: The drafting team believes that any conflict resolution should be handled through normal company practices. Note that the drafting team changed from agreement to confirm acceptance.
- Some commenters wanted the drafting team to further modify PRC-001-2 by adding a Measure for Requirement R1 or retire the standard. This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, “The drafting team recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to

an existing standard or development of a new standard". Note: PRC-001-1 Requirement 1 never had an associated measure.

- Some commenters expressed concern over the number of time frames associated with the coordination process and the burden of documentation. The drafting team believes the assigned time frames and documentation are appropriate and necessary and declined to make any changes.
- A few commenters wanted time frames to be established for Requirement R1, Part 1.1.3. The drafting team reiterated that there is not a single time frame that would be appropriate for every project and chose not to modify the standard.

Index to Questions, Comments, and Responses

1. The SDT established the following Purpose for this standard: “To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.” Do you agree with this Purpose? If not, please provide specific suggestions for changes to the purpose in the comment area. 18
2. The SDT assigned the Applicability of PRC-027-1 to Transmission Owners, Generator Owners and Distribution Providers that own the Protection Systems applied at the Interconnected Facilities that require coordination for isolating generation and Transmission Faults. Are you aware of other functional entities that should be included in the Applicability? If so, please provide specific suggestions in the comment area and the reason for including those functional entities. 43
3. In Requirement R1, the SDT allowed a responsible entity 36 months to have a documented Protection System Study completed for each Interconnected Facility if the responsible entity does not already have a Protection System Study for that Interconnected Facility performed on or subsequent to June 18, 2007 (the effective date of PRC-001-1). Do you agree with this time frame? If not, please provide specific suggestions for change in the comment area. 59
4. In Requirement R2, the SDT established a +/- 10 % change in an Interconnected Facility’s Fault current value as a criterion for notifying interconnected entities to give the interconnected entity a “heads up” that a review of the existing documented Protection System Study may be warranted. Do you agree with the +/- 10 % Fault current threshold for initiating this review? If not, please provide an alternative means along with a technical justification for determining a threshold. 88
5. In Requirement R3, the SDT included a list of proposed changes that impact the coordination of Protection Systems and would initiate a need to inform other entities. Do you agree that this is an appropriate and inclusive list? If not, please provide specific suggestions for additions or deletions with your reasoning(s) in the comment area. 116
6. In Requirement R4, the SDT required that agreement must be reached prior to implementation of proposed Protection System changes except under the conditions identified in Requirement 3, Part 3.3. Do you agree with this need? If not, please specify reasons in the comment area. 146
7. In Requirement R4, the SDT established a 90 day time frame for responding to a request for agreement with a Protection System Study. Do you agree with this time frame? If not, please provide specific suggestions with your reasoning(s) in the comment area. 165
8. The team included VRFs, VSLs, and Time Horizons with this posting. Do you agree with the assignments? If not, please provide specific suggestions for change. 183

9. If you have any other comments that you have NOT provided in response to the above questions, please provide them here. (Please do not repeat comments that you provided elsewhere.) 196

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	MRO	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	NPCC	5, 6
4.	Michael Crowley	Dominion Virginia Power	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Jonathan Hayes	Southwest Power Pool NERC Reliability Standards Development Team	X	X		X						

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	Sean Simpson	Board of Public Utilities of Kansas City, Kansas	SPP	NA

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
4.	Willy Haffecke	City Utilities of Springfield	SPP	1, 4
5.	Fred Ipock	City Utilities of Springfield	SPP	1, 4

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Michael Jones	National Grid USA / Niagara Mohawk	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Schiavone	Niagara Mohawk (National Grid)	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	David Thorne	Pepco Holdings Inc. & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light	RFC	1
2.	Mark Godfrey	Pepco Holdings	RFC	1
3.	Alvin Depew	Pepco	RFC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Sasa Maljukan	Hydro One	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc.	NPCC	1
2.	Paul Difilippo	Hydro One Networks Inc.	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jose Landeros	IID	WECC	1, 3, 4, 5, 6
2.	Lupe Ontiveros	IID	WECC	1, 3, 4, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean	Bender	WECC	1
2.	Fran	Halpin	WECC	5
3.	Erika	Doot	WECC	3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	L. Raczkowski	FE	RFC	
2.	J. Detweiler	FE	RFC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

3.	B. Orians	FE	RFC	
4.	D. Hohlbaugh	FE	RFC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Shawn T. Abrams	Santee Cooper	SERC	1
2.	Bridget Coffman	Santee Cooper	SERC	1
3.	Rene' Free	Santee Cooper		1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Kent Kujala	Detroit Edison			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Barbara Holland			3, 4, 5
2.	Karie Barczak			3, 4, 5
3.	David Szulczewski			3, 4, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Steve Alexanderson P.E.	Western Small Entity Comment Group			X	X					X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dale Dunckel	Okanogan PUD	WECC	1
2.	Ronald Sporseen	Blachly-Lane Electric Cooperative	WECC	3
3.	Ronald Sporseen	Central Electric Cooperative	WECC	3
4.	Ronald Sporseen	Consumers Power	WECC	1, 3
5.	Ronald Sporseen	Clearwater Power Company	WECC	3
6.	Ronald Sporseen	Douglas Electric Cooperative	WECC	3
7.	Ronald Sporseen	Fall River Rural Electric Cooperative	WECC	3
8.	Ronald Sporseen	Northern Lights	WECC	3
9.	Ronald Sporseen	Lane Electric Cooperative	WECC	3
10.	Ronald Sporseen	Lincoln Electric Cooperative	WECC	3
11.	Ronald Sporseen	Raft River Rural Electric Cooperative	WECC	3
12.	Ronald Sporseen	Lost River Electric Cooperative	WECC	3
13.	Ronald Sporseen	Salmon River Electric Cooperative	WECC	3
14.	Ronald Sporseen	Umatilla Electric Cooperative	WECC	3
15.	Ronald Sporseen	Coos-Curry Electric Cooperative	WECC	3
16.	Ronald Sporseen	West Oregon Electric Cooperative	WECC	3
17.	Ronald Sporseen	Pacific Northwest Generating Cooperative	WECC	3, 8
18.	Ronald Sporseen	Power Resources Cooperative	WECC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
13.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid		1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co.of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	DAN INMAN	MPC	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates					X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
2.			WECC	5
3.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6
4.			NPCC	6
5.			SERC	6
6.			SPP	6
7.			RFC	6
8.			WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Joe Spencer	SERC Protection and Control Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Andrew Monroe	Georgia Power (So. Co.)	SERC	
2.	Paul Nauert	Ameren	SERC	
3.	Charlie Fink	Entergy	SERC	
4.	Russ Evans	SCANA	SERC	
5.	Steve Edwards	Dominion/Va Power	SERC	
6.	Jay Farrington	PowerSouth	SERC	
7.	John Miller	GTC	SERC	
8.	Ernesto Paon	MEAG Power	SERC	
9.	Phil Winston	Georgia Power (So. Co.)	SERC	
10.	Bridget Coffman	Santee Cooper	SERC	
11.	George Pitts	TVA	SERC	

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
12.	David Greene	SERC	SERC	
13.	Joe Spencer	SERC	SERC	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Jennifer Eckels	Colorado Springs Utilities	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Morland		WECC	1
2.	Charles Morgan		WECC	3
3.	Lisa Rosintoski		WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Charles Yeung	ISO RTO Council SRC		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Gary DeShazo	CAISO	WECC	
2.	Steve Myers	ERCOT	ERCOT	
3.	Matt Goldberg	ISONE	NPCC	
4.	Bill Phillips	MISO	MRO	
5.	Greg Campoli	NYISO	NPCC	
6.	Stephanie Monzon	PJM	RFC	
7.	Don Weaver	NBSO	NPCC	
8.	Ken Gardner	AESO	WECC	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Larry Akens		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Group	Mary Jo Cooper	GP Strategies	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Elizabeth Kirkley	City of Lodi	WECC	3
2.	Angela Kimmey	Pasadena Water and Power	WECC	1, 3
3.	Douglas Dreager	Alameda Municipal Power	WECC	3
4.	Ken Dizes	Salmon River Electric Co-op	WECC	1, 3
5.	Sam Rohn	California Pacific Electric Co.	WECC	3
6.	Colin Murphey	City of Ukiah	WECC	3
7.	Michael Knott	Granite State Electric	NPCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Group	David Dockery	Associated Electric Cooperative, Inc.,	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			JRO00088										

Additional Member	Additional Organization	Region	Segment Selection	
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
22.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
2.	John Shaver	Arizona Electric Power Cooperative Inc.	WECC	4, 5
3.	John Shaver	Southwest Transmission Cooperative Inc.	WECC	1
4.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
5.	Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5
6.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1

				1	2	3	4	5	6	7	8	9	10
23.	Group	Tim Hinken	Kansas City Power & Light	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Michael Gammon	Kansas City Power & Light	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
24.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
25.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
26.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
27.	Individual	Ed Croft	Operational Compliance	X		X		X					
28.	Individual	John Hagen	Pacific Gas and Electric Company	X		X		X					
29.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
30.	Individual	Michael Falvo	Independent Electricity System Operator		X								
31.	Individual	Thad Ness	American Electric Power	X		X		X	X				
32.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X					

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
33.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.				X						
34.	Individual	Anthony Jablonski	ReliabilityFirst										X
35.	Individual	Martin Kaufman	ExxonMobil Research & Engineering	X		X		X		X			
36.	Individual	Jonathan Meyer	Idaho Power Company	X		X							
37.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
38.	Individual	Don Jones	Texas Reliability Entity										X
39.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
40.	Individual	Martyn Turner	LCRA Transmission Services Corporation	X									
41.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
42.	Individual	Chris Scanlon	Exelon	X		X		X	X				
43.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
44.	Individual	David Gordon	Massachusetts Municipal Wholesale Electric Company					X					
45.	Individual	Bill Middaugh	Tri-State G & T	X									
46.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
47.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
48.	Individual	Kirit Shah	Ameren	X		X		X	X				
49.	Individual	John D. Martinsen	Public Utility District No. 1 of Snohomish County	X		X	X	X	X				
50.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP, (Occidental Chemical Corporation)					X					
51.	Individual	John W Miller	Georgia Transmission Corporation	X									
52.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
53.	Individual	Rich Salgo	NV Energy	X		X		X					
54.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
55.	Individual	Mike Weir	Dairyland Power Cooperative	X		X		X					
56.	Individual	Deborah Schaneman	Platte River Power Authority	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
57.	Individual	E Hahn	MWDSC	X									
58.	Individual	Angela P Gaines	Portland General Electric Company	X		X		X	X				
59.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
60.	Individual	Rick Koch	Southern Minnesota Municipal Power Agency				X		X				
61.	Individual	Don Schmit	NPPD	X		X		X					
62.	Individual	Brian Evans-Mongeon	Utility Services								X		
63.	Individual	daniel	mason	X				X					
64.	Individual	Rowell Crisostomo	ATCO Electric	X									
65.	Individual	Bob Thomas and Kevin Wagner	Illinois Municipal Electric Agency				X						
66.	Individual	Rhonda Bryant	El Paso Electric Company	X									
67.	Individual	Steven Powell	Trans Bay Cable	X							X		
68.	Individual	Daniela Hammons	CenterPoint Energy	X									
69.	Individual	Laura Lee	Duke Energy	X		X		X	X				
70.	Individual	Jack Stamper	Clark Public Utilities	X									
71.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
72.	Individual	Brian J Murphy	NextEra Energy Inc	X		X		X	X				
73.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
74.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
75.	Individual	Jian Zhang	TransAlta Centralia Generation LLC					X					
76.	Individual	Pablo OÃ±ate	El Paso Electric	X		X		X	X				

1. **The SDT established the following Purpose for this standard: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards." Do you agree with this Purpose? If not, please provide specific suggestions for changes to the purpose in the comment area.**

Summary Consideration:

The responses were equally split between yes and no. Many negative comments related to the inclusion of the phrase '… while meeting the system performance specified within requirements established in other approved NERC Reliability Standards'. Several comments related to the phrase '… remove from service only those Elements ...' due to the fact that some designs include multiple elements within a single protection zone such as bank/bus differential schemes. Suggestions included eliminating 'only' or to add 'as designed'. The Purpose has been modified as follows which addresses the large majority of the negative comments.

Purpose: To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear faults.

Organization	Yes or No	Question 1 Comment
Dominion	No	1. Dominion supports the stated purpose up to the comma. The qualifying language after the comma is ambiguous and not supported in the Requirements of this standard. 2. In the current PRC-001-1 standard the meaning of the term "coordination" has and still is interpreted in two ways. One interpretation is viewed from the technical aspect as "relay coordination" and the second is viewed from an inter-communication aspect as "coordination of information" between entities. The term "coordination" should be removed from the new standard Title and Purpose. a. Recommend changing **Title** to: <u>"Protection System Interconnected Facility Performance During Faults".</u> Also, recommended is to change the **Purpose** to read<u>: "To communicate and exchange Protection</u>

Organization	Yes or No	Question 1 Comment
		System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those Elements required to isolate Faults." In PRC- 027-1, use the term coordination only when referring to the technical aspects of the relay coordination within a Requirement when applicable. b. Under **Purpose**, delete: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet 'the system performance specified within requirements established in other approved NERC Reliability Standards' and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1.
Response: Thank you for your comment. **Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."** **a. The drafting team agrees that the use of the term "coordination" in PRC-001 did result in multiple meanings and potential confusion. The drafting team believes the use of "coordination" in this standard clearly relates to the technical aspects of relay coordination and respectfully declines to make the suggested changes.** **b. Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."**		
Southwest Power Pool NERC Reliability Standards Development Team	No	We would ask that the team revise the second part of the purpose to lead in with "In accordance with the system performance specified within requirements established in other approved NERC Reliability Standards" If

Organization	Yes or No	Question 1 Comment
		left as is it reads like you are required to do both the first and second parts of the purpose. This proposed language requires the initial goal of this standard and references that it will do so under the system performance specified in NERC standards.
Response: Thank you for your comment. **Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."**		
Pepco Holdings Inc. & Affiliates	No	1) The language in the Statement of Purpose needs to be reworded. The phrase "remove from service only those elements required to isolate faults" may restrict certain protection practices in widespread use today, where coordination on tapped distribution facilities is achieved via auto-reclosing rather than via coordinated time delays. For example, a BES line (protected by a high speed DCB or POTT pilot scheme) is tapped by a distribution provider as demonstrated in Figure 3 of the Application Guidelines. Very often for distribution taps like these, rather than requiring the distribution provider to establish a costly transmission class pilot scheme terminal at breaker C with communication links to A & B, it is common to let the pilot scheme reach into (but not thru) the transformer at C. For faults in the transformer the high speed transformer relays will operate to trip and lockout breaker C. However, the pilot scheme at A & B will also trip simultaneously. Breaker C will lockout and A & B will auto-reclose to restore the line. Coordination is achieved via auto-reclosing. For faults on the line, A & B will trip via the pilot scheme, and if generation happens to be running either C will trip, or the generator will trip depending on scheme design. Reclosing at A & B would be delayed and / or voltage supervised to ensure generation has been removed prior to auto-reclosing. In the above scenarios since the line tripped for a fault in the transformer, or the generator tripped for a

Organization	Yes or No	Question 1 Comment
		fault on the line, it would violate the requirement to "remove from service only those elements required to isolate faults". The language used in the proposed definition of Protection System Study is slightly better, using the phrase "demonstrates ... Protection Systems operate in the desired sequence for clearing faults". 2) The problem here is who determines what is the "desired sequence"? Would a scheme, which is purposely designed as described above and acknowledged by the Transmission Planner and Transmission Operator, be considered to operate in the "desired sequence" for clearing faults? 3) The language in the standard needs to be re-visited to enable these types of protection interfaces with distribution providers having limited generation resources connected downstream. Also, if system reliability was truly an issue for this example, the interconnection should not have been a simple tap on the line, but rather a ring bus should have been established at the interconnection point.

Response: Thank you for your comment.

1. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults". The Purpose states the reason for the standard and is the basis for everything else in the standard, but the Purpose is not a requirement and is not mandatory or enforceable. The individual requirements support the goal or Purpose of the standard.**
2. **Determining the "desired sequence" is the purpose of the Protection System Study agreed to by all parties involved.**
3. **The drafting team believes Distribution Providers that own Protection Systems installed for the primary function of detecting Faults on BES Elements should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners. To add clarity to this issue, the drafting team revised Applicability Section 4.2 as follows: Protection Systems installed at Interconnected Stations for the primary function of detecting Faults on BES Elements. Additionally, the drafting team changed the term "Interconnected Facilities" to Interconnected Elements" defined as follows: "An Element that electrically joins separate Functional Entities, including**

Organization	Yes or No	Question 1 Comment
those Functional Entities that are a part of the same Registered Entity".		
Hydro One	No	1. The goal of this standard is to address co-ordination of protection systems between neighboring entities. To achieve this goal, the efforts should focus on the co-ordination of protections between entities as outlined and described in the NERC SPCS paper "Power Plant and Transmission System Protection Co-ordination - Technical Reference Document (TRD)," dated July 2010. This standard should include the review/study of all protections requiring coordination not the ones dealing with faults only as identified in the above TRD. There should be one comprehensive study/report not spread out into 7-8 standards. If so, there are still protection elements that require coordination that have not been addressed such as: open-phase, loss-of-field, over-excitation, out-of-step, and negative sequence normal unbalance, etc. We don't see how a standard for Protection system co-ordination can rely on other standards to achieve the goal of co-coordinating protections for both Faults and other conditions that challenge co-ordination. 2. The Purpose should be: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate from abnormal system conditions, while meeting the system performance specified within requirements established in NERC TPL Reliability Standards."If the above suggestions are not taken into consideration and the SDT decides to keep the requirements in the current form, the statement"...while meeting the system performance specified within requirements established in other approved NERC Reliability Standards." should be changed to include exact reference to standards or at least group of standards the SDT is referring to.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. 1. **As noted in the Background information section, the drafting team believes that other aspects of coordination are or should be covered by other standards and it is appropriate for this standard to be limited to the stated Purpose.** 2. **Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."**		
Imperial Irrigation District (IID)	No	The SDT proposed Purpose is confusing. IID proposes the following Purpose language: "To coordinate Protection Systems for Interconnected Facilities, such that during faults, those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."
Response: Thank you for your comment. **The drafting team does not see the confusion in the present language and respectfully declines to make the suggested change. The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults".**		
Bonneville Power Administration	No	The purpose of PRC-001-1 was "To ensure system protection is coordinated among operating entities." With the rewrite of PRC-001 to PRC-027, the standard drafting team has expanded the purpose to specify that only elements required to isolate faults are removed from service and that system performance established in other NERC standards is met. The two additions to the purpose of PRC-027 should be removed for the reasons described below. 1) The statement in the purpose, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards", only serves to unnecessarily complicate the purpose statement. BPA recognizes that the NERC standard does not

Organization	Yes or No	Question 1 Comment
		void the requirements of other NERC standards; therefore, there is no need to state in the purpose that other NERC standards must be met. 2) The statement in the purpose, “such that those Protection Systems remove from service only those Elements required to isolate faults”, drastically expands the scope of PRC-027 over PRC-001. With this new purpose, BPA believes this puts NERC in the position of micromanaging how protection systems are applied. Although most protection schemes are intended to remove only the faulted element, it is not necessarily a problem if additional elements are removed, and there might even be reasons to remove additional elements. In some cases it might be significantly less expensive to design a scheme that allows the removal of additional elements. Protection engineers need to have the flexibility to apply protection schemes that meet the requirements of the project at hand. Creating standards with absolute requirements on how protection schemes are applied and set will eliminate the flexibility necessary to implement effective and efficient protection schemes. The Standard Drafting Team (SDT) does not have the ability to foresee all possible protection scenarios, and to create a standard whose purpose is to remove from service only those elements required to isolate faults will create unnecessary expense and difficulty. BPA strongly recommends that the statement “such that those Protection Systems remove from service only those Elements required to isolate faults” be removed from the purpose and that the standard be modified to eliminate this requirement.
Response: Thank you for your comment. **1. Based on yours and others comments, the drafting team removed the phrase: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.”** **2. The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such**		

Organization	Yes or No	Question 1 Comment
that the least number of power system Elements are isolated to clear Faults". The Purpose states the reason for the standard and is the basis for everything else in the standard, but the Purpose is not a requirement and is not mandatory or enforceable. The individual requirements support the goal or Purpose of the standard.		
FirstEnergy	No	We do not believe the phrase "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" is needed and may be confusing to the reader.
Response: Thank you for your comment. **Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."**		
Santee Cooper	No	It would probably be good to avoid using the term "coordination" as it can be considered as having two meanings, either the "coordinating" of the exchange of the data or the "coordinating" of the actual protective devices. Coordination should be taken out of the title and the purpose. "To Coordinate Protection Systems" could be changed to "To communicate and exchange Protective System data..." in the Purpose. The title could be changed to "Protection System Interconnected Facility Performance during faults"
Response: Thank you for your comment. **The drafting team agrees that the use of the term 'coordination' in PRC-001 did result in multiple meanings and potential confusion. The drafting team believes that the use of the term in this standard is clear and has not removed the term from the Title nor Purpose.**		
Detroit Edison	No	It is suggested that ". . . the system performance specified within requirements established in other approved NERC Reliability Standards" be specified so that what needs to be met is clear.
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		

Organization	Yes or No	Question 1 Comment
Western Small Entity Comment Group	No	The language "...remove from service only those Elements required to isolate Faults..." is problematic. Taken literally; only the faulted Element may be isolated, and any adjoining buswork or lines (separate Elements) must remain energized; even the result is no change in the loss of load or capacity. We suggest ""To coordinate existing Protection Systems..." to ensure that this is not interpreted as a construction standard requiring additional Protection Systems.
Response: Thank you for your comment. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults". The Purpose states the reason for the standard and is the basis for everything else in the standard, but the Purpose is not a requirement and is not mandatory or enforceable. The individual requirements support the goal or Purpose of the standard.**		
PPL Corporation NERC Registered Affiliates	No	PRC-027 appears to have been written exclusively for vertically integrated power companies, and there is no justification for making the proposed standard applicable to independent GOs. The only role an independent GO fulfills in isolating faults is to trip the breaker if the generator or GSU has a problem; everything involving sequencing is in the Transmission Owner's (TOs) or Distribution Providers (DPs) system. Independent GOs are owned by separate legal entities than the applicable TO or Distribution Provider [DP] to which they are interconnected. Such GOs do not have the capability to perform the type of TO/DP system studies that appear to be contemplated by the SDT. The actions required of independent GOs should be to perform Protection System maintenance and supply data to other applicable entities, per existing standards PRC-005-1 and PRC-001-1.1, respectively.
Response: Thank you for your comment. **The drafting team believes that the Owner of the Protection System is responsible for ensuring its Protection Systems are coordinated with others. It is acknowledged that in many cases, the majority of the work associated with this task will fall on**		

Organization	Yes or No	Question 1 Comment
the Transmission Owner; however, the coordination of some Protection Systems owned by Generator Owners installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included.		
SERC Protection and Control Subcommittee	No	a) Recommend under Purpose, deleting: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet ‘the system performance specified within requirements established in other approved NERC Reliability Standards’ and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003R1.3.7 already requires the entity to “demonstrate that system performance meets its Table 1 for Category C contingencies” (TPL-001, -002 have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1. b) The term “coordination” should be removed from the new standard Title and Purpose. Recommend changing Title to “Protection System Interconnected Facility Performance during Faults”. Also recommended is to change the Purpose to read “To communicate and exchange Protection System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those Elements required to isolate Faults.” In PRC 027, using the term coordination should only be referenced when referring to the technical aspects of the relay coordination within a requirement when applicable. (In the current PRC 001 standard the meaning of the term “coordination” has, and still is, interpreted in two ways. One interpretation is viewed from the technical aspect as “relay coordination” and the second is viewed from an inter-communication aspect as “coordination of information” between

Organization	Yes or No	Question 1 Comment
		entities).
Response: Thank you for your comment. a. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".** b. **The drafting team agrees that the use of the term 'coordination' in PRC-001 did result in multiple meanings and potential confusion. The SDT believes that the use of the term in this standard is clear and has not removed the term from the Title nor Purpose.**		
ISO RTO Council SRC	No	Is the intent of the coordination that is expected limited only to those protection systems related to intertie facilities between facilities owners? Or is the intent of the proposed standard to require coordination of protection systems to take into account outage and/or operating conditions between facilities owners beyond the immediate intertie facilities? In other words is this coordination requirement expected to be applied to relays that may not be directly involved in protection of intertie equipment?
Response: Thank you for your comment. **The intent of this standard is focused on those Protection Systems directly associated with the Facility Interconnections. However, as noted in R.3.1 it is recognized that there may be changes or additions either at an existing or new Facility associated with the Interconnected Element, or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).**		
Tennessee Valley Authority	No	a) The term "coordination" should be removed from the new standard Title and Purpose. Recommend changing Title to: "Interconnected Facility Protection System Performance During Faults". Also recommend changing the Purpose to read: "To communicate and exchange Protection System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those elements required

Organization	Yes or No	Question 1 Comment
		to isolate faults." b) Recommend under Purpose, deleting: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” as it is superfluous and could cause duplicative or conflicting work. The purpose without this clause is clear, concise, and consistent with the rest of the 1st draft of this standard. The resulting coordinated Protection System must meet ‘the system performance specified within requirements established in other approved NERC Reliability Standards’ and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003 R1.3.7 already requires the entity to “demonstrate that System performance meets its Table 1 for Category C contingencies” (TPL-001, -002 have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1. c) In PRC 027, the term "coordination" should only be referenced when referring to the technical aspects of the relay coordination within a Requirement when applicable. (In the current PRC 001 standard the meaning of the term “coordination” has and still is interpreted in two ways. One interpretation is viewed from the technical aspect as “relay coordination” and the second is viewed from an inter-communication aspect as “coordination of information” between entities).

Response: Thank you for your comment.

a. **The drafting team agrees that the use of the term ‘coordination’ in PRC-001 did result in multiple meanings and potential confusion. The drafting team believes that the use of the term in this standard is clear and has not removed the term from the Title nor Purpose.**

b. **Based on all the comments received, the drafting team has removed the phrase “…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards”.**

Organization	Yes or No	Question 1 Comment
Associated Electric Cooperative, Inc., JRO00088	No	See comments posted by SERC PCS
Response: See response to SERC Protection and Control Subcommittee.		
ACES Power Marketing Standards Collaborators	No	Please strike "while meeting the system performance specified within requirements established in other approved NERC reliability standards." It provides no additional explanation for the purpose and these "other approved NERC reliability standards" apply regardless of this standard. In generally, it is not necessary to reference other NERC standards within a standard and, in fact, should be avoided as a standard should stand alone.
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
Kansas City Power & Light	No	1. The reliability objective of this standard should be to insure that there is an agreement between two interconnected entities of relay protection schemes and relay protection settings for the interconnected facilities. This is achieved if there is documentation stating that the Interconnected operating companies have reached agreement on protection schemes and protective relay settings. This standard should only require documentation that neighboring owners are talking and agreeing with one another in relation to protection and control. 2. The present purpose makes it appear that you are in violation of the standard any time the system has a misoperation because of relay setting regardless of whether both parties have agreed on the settings used but the measures tend to measure agreement with the other entity. This is the reason that the present purpose needs to be

Organization	Yes or No	Question 1 Comment
		rewritten the auditors may interpret the purpose to indicate any misoperation due to setting issues is a violation.
Response: Thank you for your comment. 1. **The drafting team believes the standard does exactly what you stated. The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults". The Purpose states the reason for the standard and is the basis for everything else in the standard, but the Purpose is not a requirement and is not mandatory or enforceable. The individual requirements support the goal or Purpose of the standard.** 2. **The drafting team disagrees with the misoperation issue you describe. Misoperations can occur even when Protection Systems are fully coordinated and agreed upon.**		
Southern Company	No	1) Reference the 'required to isolate Faults '. In some cases the design of the protection system may take more Elements out than the faulted element, such as a transformer differential that trips a transmission bus and then opens a HS Bank disconnect. For this reason we would prefer the term 'as designed' be used. 2) We feel that it is important to identify the Protection Systems that are to be evaluated; perhaps a clear reference to the NERC Technical reference document?
Response: Thank you for your comment. 1. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults".** 2. **The Protection Systems that must be evaluated are those that are identified in the Applicability section of this standard.**		
Western Area Power Administration	No	Don't necessarily agree with the statement: "Protection Systems remove from service only those Elements required to isolate Faults..." This statement can be problematic since backup functions such as remote

Organization	Yes or No	Question 1 Comment
		Zone 3 distance elements cannot be overlapped reliably yet are necessary for N-2 and beyond contingencies. Also, in some case it may be desirable to allow for intentional overlap or mis-coordination depending on the circumstances. These issues need to be resolved in the proposed standard or the standard eliminated.
Response: Thank you for your comments. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults".**		
Independent Electricity System Operator	No	We agree with the first part of the purpose statement, but do not find it necessary to include the second part since "meeting the system performance specified within requirements established in other approved NERC Reliability Standards" is universally true for all standards. No one single standard can assure reliability on its own; multiple standards must be complied with to meet one or more reliability objectives and performance targets. We suggest to remove the part "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
American Electric Power	No	AEP recommends the removal of the language, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards". AEP recommends as an alternative to the removal of the language, modification of the language to reference the TOP standards that should be adhered to in conjunction with PRC-027.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
Texas Reliability Entity	No	We support this reliability objective, but feel that it may fall short of fulfilling all of the required Protection System coordination needs, resulting in a gap in the Standards. The major issue that we see in Protection System coordination is with coordination studies conducted WITHIN an individual entity, not between two or more entities. Using the Misoperation data as an indication, for CY2011, out of 202 total Misoperations in the ERCOT region, 46% were due to "Incorrect settings/logic design", however, less than 2% of the Misoperations occurred on Interconnected Facilities between different entities. This suggests the main problem with Protection System coordination is internal to an entity, not between two different entities. This Standard, as well as PRC-001, are somewhat silent as to what internal coordination should be considered "Good Utility Practice", even though there have been instances where internal coordination was not done.
Response: Thank you for your comment. **The previous PRC-001 only applied to coordination between TOPs, GOPs and BAs. The drafting team has chosen not to include internal facilities for two main reasons: the extreme documentation burden that would be involved for minimal benefit as most of this work is done by the same organization, and the drafting team believes that the entities' internal facilities are completely in their control and are the responsibility of the entity. Failure to properly design and implement internal Protection Systems would be an internal lack of procedures and/or a human performance issue which are both outside the scope of this standard. Additionally, PRC-004 requires that entities have corrective actions plans for identified Misoperations which would prevent similar Misoperations.**		
LCRA Transmission Services Corporation	No	Reword the Purpose to state as follows: "To allow for the coordination of Protection Systems at Interconnected Facilities to prevent equipment damage while maintaining proper selectivity during Faults." This phrasing is

Organization	Yes or No	Question 1 Comment
		more consistent with NERC Reliability Standard language where adherence with other reliability standards is not explicitly stated.
Response: Thank you for your comment. **The drafting team believes that restricting the purpose to "preventing equipment damage" does not meet the intended reliability objective.**		
Exelon	No	1. The current Purpose for PRC-027-1 should more clearly and concisely state the purpose of the standard by relating the purpose of the standard to the definition of Protection System Study (the key element of the proposed PRC-027). 2. The statement, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards", is likely to be subject to interpretation by registered entities and auditors alike and cause confusion. The specific Standards should be referenced in a footnote, or the reference should be removed. [For the purposes of this comment and the suggested revision, Exelon removed the reference since we believe this is the best option].Exelon suggests the following revised Purpose "To ensure Protection Systems at Interconnected Facilities operate in the desired sequence to isolate a fault." In our experience, the term "coordinate" (or "coordination") caused confusion in PRC-001-1 and therefore Exelon proposes that the term be omitted. 3. In PRC-001-1, the term "coordination" was unofficially accepted as either the correspondence or communication between entities (i.e., via email, memo, fax, etc.), or as the time response relationship associated with backup protection elements. Thus, to avoid this confusion and to match to the proposed Protection System Study definition, Exelon removed it from our suggested Purpose statement above. If the SDT believes that the term "coordination" should

Organization	Yes or No	Question 1 Comment
		remain, it should be clearly defined. Given the Protection System Study definition, a suggested definition for coordination would be "operation of Protection Systems in the desired sequence to isolate a fault".
Response: Thank you for your comment. 1. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults". The drafting team believes that the Purpose does not need to address its relation to the Protection System Study in order to accurately reflect the goal of the standard.** 2. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".** 3. **The drafting team agrees that the use of the term "coordination" in PRC-001 did result in multiple meanings and potential confusion. The drafting team believes that the use of the term in this standard is clear and has not removed the term from the Title nor Purpose.**		
Ameren	No	We recommend that the SDT delete the last part of the purpose "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet 'the system performance specified within requirements established in other approved NERC Reliability Standards' and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003 R1.3.7 already requires the entity to "demonstrate that System performance meets its Table 1 for Category C contingencies" (TPL-001, -002 also have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
Georgia Transmission Corporation	No	The title should state the same as the purpose. Example: "Protection System Coordination of Interconnected Facilities". The purpose is to make each entity communicate protection system and/or facility changes in order to make coordination changes as needed.
Response: Thank you for your comment. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults". The drafting team believes the Title and Purpose, as separate components of the standard, are not obligated to be the same.**		
Dairyland Power Cooperative	No	The NERC Protection System definition includes more elements than would need to be coordinated at interconnecting facilities (e.g. batteries, chargers). Please consider revising to include only the protection elements that would need to be coordinated to remove Elements from service to isolate Faults.
Response: Thank you for your comment. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults". The drafting team does not see that specific Protection System elements referenced (Batteries and chargers) would be considered in doing a Protection System Study; therefore, your suggested changes have not been made.**		
NPPD	No	Suggestion: Remove "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" since there are other standards that are or will be in place otherwise it sounds like the other standards must have evidence included

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>for this standard documentation as well. Perhaps this standard is not required if the other performance standards are adhered to or have portions of this draft standard included in them.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".</td></tr>
<tr><td>Utility Services</td><td>No</td><td>The purpose should specifically state whether or not this standard applies to BES Elements or all Elements. In consideration of other PRC reliability standards, this standard uses language that implies applicability to all Elements. Under the NERC Standard Development Process, standards are only to be applied to BES equipment, unless the applicability language specifically states a broader application. This standard implies it but does not specifically state it. The standard should be modified to clear up any confusion.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The definition of Interconnect Facilities has been modified as follows: Interconnected Elements: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity". The Applicability section has been modified as follows: Facilities: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements".</td></tr>
<tr><td>Trans Bay Cable</td><td>No</td><td>The language "...remove from service only those Elements required to isolate Faults..." is problematic. Taken literally; only the faulted Element may be isolated, and any adjoining buswork or lines (separate Elements) must remain energized; even the result is no change in the loss of load or capacity. We suggest ""To coordinate existing Protection Systems..." to ensure that this is not interpreted as a construction standard requiring additional Protection Systems.</td></tr>
</table>

NERC

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. **The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults”.**		
Oncor Electric Delivery Company LLC	No	Oncor takes the position that the word "only" in the Purpose is too subjective and allows for multiple interpretations. Oncor believes that in order to provide clarity, Oncor suggest that the Purpose be modified as follows:"To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.
Response: Thank you for your comment. **The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults”.**		
TransAlta Centralia Generation LLC	No	The Interconnected Facilities definition is not clear.
Response: Thank you for your comment. **The term “Interconnected Facilities” has been changed to “Interconnected Element” and reads as follows: “An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity”. More details related to why it is not clear are needed prior to addressing your comment.**		
ExxonMobil Research & Engineering	No	
MRO NSRF	Yes	The last part of the purpose, “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” is vague and open-ended. The NSRF recommends that the SDT refer to the TPL standards if the intent is to limit responsibility for correct

Organization	Yes or No	Question 1 Comment
		coordination to studied system contingencies
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
Colorado Springs Utilities	Yes	There are cases of weak system interconnected facilities where proper coordination may not be achievable economically, except by severing the interconnect. Allowances should be made for these cases to prevent the severing of weak systems to meet this standard.
Response: Thank you for your comment. **The drafting team does not understand the scenario that is described. If this occurs in circumstances not accounted for in normal Protection System Studies, such as n-2 and above situations, it is not an issue.**		
Sacramento Municipal Utility District	Yes	We agree with the purpose of the standard. We disagree with the execution of this purpose. This standard only addresses a very narrow reliability issue. Does the SDT really believe that this narrow concern needs all the documentation called for in the standard? At a minimum, a Protection System Study, proof that you checked for a +/- 10% Fault current change regularly, and proof that you have communicated with other registered entities on these issues? And this will be for every interconnection. We believes this is regulatory overkill and not indicative of a results based standard.
Response: Thank you for your comment. **The drafting team believes the documentation identified in the requirements is necessary to support the purpose.**		
Public Utility District No. 1 of Snohomish County	Yes	1. We agree with the purpose of the standard. We disagree with the execution of this purpose. This standard only addresses a very

Organization	Yes or No	Question 1 Comment
		narrow reliability issue. Does the SDT really believe that this narrow concern needs all the documentation called for in the standard? At a minimum, a Protection System Study, proof that you checked for a +/- 10% Fault current change regularly, and proof that you have communicated with other registered entities on these issues? And this will be for every interconnection. We believes this is regulatory overkill and not indicative of a results based standard.
Response: Thank you for your comment. **The drafting team believes the documentation identified in the requirements is necessary to support the purpose.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	Yes	Ingleside Cogeneration LP agrees that PRC-027-1 should be tightly focused on Fault isolation only. There are other PRC standards which govern the coordination of UFLS, SPS, phase-distance, and other relay types.
Response: Thank you for your support.		
National Grid USA / Niagara Mohawk	Yes	
Luminant	Yes	
Northeast Power Coordinating Council	Yes	
GP Strategies	Yes	
Progress Energy	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	

Organization	Yes or No	Question 1 Comment
Pacific Gas and Electric Company	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Idaho Power Company	Yes	
City of Austin dba Austin Energy	Yes	
Manitoba Hydro	Yes	
Xcel Energy	Yes	
Tacoma Power	Yes	
Tri-State G & T	Yes	
Public Service Enterprise Group	Yes	
Liberty Electric Power LLC	Yes	
Wisconsin Electric Power Company	Yes	
NV Energy	Yes	
Platte River Power Authority	Yes	
MWDSC	Yes	
Portland General Electric Company	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 1 Comment
mason	Yes	
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
El Paso Electric Company	Yes	
Duke Energy	Yes	
Clark Public Utilities	Yes	
NextEra Energy Inc	Yes	
South Carolina Electric and Gas	Yes	
El Paso Electric	Yes	

2. **The SDT assigned the Applicability of PRC-027-1 to Transmission Owners, Generator Owners and Distribution Providers that own the Protection Systems applied at the Interconnected Facilities that require coordination for isolating generation and Transmission Faults. Are you aware of other functional entities that should be included in the Applicability? If so, please provide specific suggestions in the comment area and the reason for including those functional entities.**

Summary Consideration:

A large majority of the commenters did not identify any additional entities that should be added to the Applicability.

Various commenters felt that the Transmission Planner, Planning Authority, Transmission Operator and/or Generator Operator should be included. The basis for these requests was the fact that in some cases those entities were identified as providing the Protection System Studies and/or system modeling services for the Owners. An example response to these comments was as follows: The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others.

Several commenters disagreed with the Distribution Provider being included. The drafting team responses indicated that the inclusion of Distribution Providers was appropriate. The drafting team responded that they believe the Distribution Providers that own "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements" should be included in the Applicability of this standard because those Protection Systems must be coordinated with the Protection Systems of other Facility owners.

A few commenters asked for clarification as to whether the standard applied to entities that had multiple registrations (i.e. as a TO and GO). An example response to these questions was as follows: If Entity A is registered as a Transmission Owner and a Generator Owner then all aspects of this standard would apply to the Interconnected Facilities between Entity A- Transmission Owner and Entity A-Generator Owner. The drafting team will review the language in order to ensure clarity related to this.

The Applicability was slightly modified as a result of these comments and others as follows: 4.2 Facilities: Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.

Organization	Yes or No	Question 2 Comment
FirstEnergy	No	However, it should be clear the DP facilities in scope are only those associated with potentially impacting a BES facility.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. **The drafting team believes Distribution Providers that own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners.** **To add clarity to this issue, the drafting team revised Applicability Section 4.2 as follows: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements". Additionally, the drafting team changed the term "Interconnected Facilities" to "Interconnected Element" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".**		
Northeast Power Coordinating Council	No	From a reliability perspective, the Applicability Section of PRC-027-1 should not include the Distribution Provider because the TO is responsible of coordination of the protection with the DP.
Response: Thank you for your comment. **The drafting team believes that the owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, if the Transmission Owner is providing such a service it would be by agreement, and does not change the fact the Distribution Provider has the responsibility.**		
MRO NSRF	No	The standard includes the definition of Interconnected Facilities as BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities. It is unclear how the requirements of the standard would apply if a registered entity would fulfill more than one functional entity role. For example if a registered entity was both a Generator Owner and Transmission Owner would the requirements of the standard apply to the interconnection of the generator and transmission facilities? It is recommended that the standard be modified to provide clarity for this situation.
Response: Thank you for your comment.		

Organization	Yes or No	Question 2 Comment
The drafting team's intent is that if Entity A is registered as a Transmission Owner and a Generator Owner then all aspects of this standard would apply to the Interconnected Facilities between Entity A- Transmission Owner and Entity A- Generator Owner. **Additionally, the drafting team changed the term "Interconnected Facilities" to Interconnected Element" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".**		
PPL Corporation NERC Registered Affiliates	No	Applicability to GOs should be limited as stated above in question #1.
Response: Thank you for your comment. **As noted in the response to #1: The drafting team believes that the Owner of the Protection System is responsible for ensuring its Protection Systems are coordinated with others. It is acknowledged that in many cases, the majority of the work associated with this task will fall on the Transmission Owner; however, the coordination of some Protection Systems owned by Generator Owners installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included.**		
Colorado Springs Utilities	No	The wording of the text suggests that Interconnected Facilities include coordination and documentation of Transmission to Distribution interfaces. Since these are usually contained in different functional or corporate entities it suggests much more documentation, and needs clarified.
Response: Thank you for your comment. **The only Transmission to Distribution interfaces included in this standard are those where the Distribution Providers own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES. Consequently, these facilities are the only ones that would require documentation.**		
Tennessee Valley Authority	No	In some instances end-use customers, such as a large industrial load, take service delivery through an Interconnected Facility. It is not clear that the draft standard covers coordination between a TO and an end-use customer (not registered as a TO, GO or DP) who takes service via a BES Interconnected Facility.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. **The drafting team changed the term "Interconnected Facilities" to Interconnected Element" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity". The standard only applies to Interconnected Element(s) between registered Transmission Owners, Generator Owners, and Distribution Providers. . To add clarity to this issue, the drafting team revised Applicability Section 4.2 as follows: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements".**		
Kansas City Power & Light	No	1. The applicability should also include Transmission Operators and Generator Operators as it is possible for jointly held facilities to be owned by several parties and operated by another party and relay protection responsibilities could be with the Operator of the facility. 2. It should be clarified the proposed Standard is applicable to Distribution Providers that provide protection for BES Elements.
Response: Thank you for your comment. **1. The drafting team believes that the Owner of the facility is responsible for ensuring that its Protection Systems are coordinated with others. It is acknowledged that in some cases the scenario described may exist; however, if the TOP or GOP is providing such a service it would be by agreement with the Owner, and does not change the fact the Owner has the responsibility.** **2. To add clarity to this issue, the drafting team revised Applicability Section 4.2 as follows: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements". Additionally, the drafting team changed the term "Interconnected Facilities" to "Interconnected Element" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".**		
LCRA Transmission Services Corporation	No	We agree that applicability of the overall standard should be limited to the Transmission Owners, Generator Owners and Distribution Providers; however, requirements for conducting the Protection System Coordination Study should only

Organization	Yes or No	Question 2 Comment
		apply to the Transmission Owners, Generator Owners and Distribution Providers that have ownership of the protective relay portion of the Protection System. Requirement R1 should read as follows:"Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System that owns a Protection System shall:"
Response: Thank you for your comment. **The drafting team believes that the Applicability section addresses this. Typically the protective relay may be the only component of the Protection System that requires review; however, that is not always the case.**		
Tri-State G & T	No	We agree with this description and the entities, however the standard's applicability is not written as described in the question. We think that "that require coordination for isolating generation and Transmission Faults" should be added to Section 4.2, Facility Applicability.
Response: Thank you for your comment. **Based on yours and others comments, the drafting team modified the Applicability section 4.2 Facilities as follows: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements".**		
Wisconsin Electric Power Company	No	The previous version, we think correctly, did not include DP's in the applicability. Since the revised definition of the BES is currently awaiting FERC approval, the applicability of this standard to the Distribution Provider function is not appropriate. The relevant entities should be limited to TO and GO only.
Response: Thank you for your comment. **The drafting team believes Distribution Providers that own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners.**		

Organization	Yes or No	Question 2 Comment
Dairyland Power Cooperative	No	It is unclear how the requirements of this standard apply to entities that fulfill multiple functional roles. For example, an entity is registered as both a Generator Owner and Transmission Owner. In the case where a GO and TO are the same entity is it required to show the same type of coordination?
Response: Thank you for your comment. **Yes. The drafting team's intent is that if Entity A is registered as a Transmission Owner and a Generator Owner then all aspects of this standard would apply to the Interconnected Element(s) between Entity A- Transmission Owner and Entity A- Generator Owner.**		
American Transmission Company	No	ATC is not aware of additional functional entities that should be included.
Response: Thank you for your support.		
NPPD	No	1. This applicability needs clarification. How does this standard relate to the definition of BES? 2. Does including Distribution Providers mean an entity that does not own a transmission protection system is included under this standard? 3. There needs to be clear understanding that radial feeds on load serving transformers such as 115/69kV or 115/34.5kV transformers and low voltage feeders are not included in this standard. 4. Perhaps NERC needs a program to evaluate/identify all functional entities and determine if they should be registered and thus applicable and not have utilities try to determine the status of other utilities or functional entities. 5. Clarify if the Transmission and Generator owner are the same utility how sharing of information is documented or confirm that this relationship means the documentation is not applicable in this standard.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. **1. The drafting team revised the Applicability of this Standard to provide more clarity, it now reads: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements"** **2. No. The drafting team believes Distribution Providers that do not own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES are not included in the Applicability of this standard.** **3. As noted in the revised Applicability section, only Facilities that have "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements" are subject to the requirements of this Standard. In general, radial feeds on load serving transformers such as 115/69kV or 115/34.5kV transformers and low voltage feeders do not have such Protection Systems applied. Please see Figure 4 in the Application Guidelines section of the draft standard PRC-027-1.** **4. This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff.** **5. How to meet the documentation requirements would be up to the entity to determine. The drafting team's intent is that if Entity A is registered as a Transmission Owner and a Generator Owner then all aspects of this standard would apply to the Interconnected Element(s) between Entity A- Transmission Owner and Entity A- Generator Owner.**		
Utility Services	No	However, using the broad term "Protection Systems", this SDT is broadening the scope of the standard beyond the BES. Due to the recent direction in Project 2007-17 for PRC-005-2, Protection Systems has been expanded to include systems beyond the definition of the BES. This project should limit the applicability for the DP to "transmission Protection Systems" as identified in PRC-004 and 005-1.
Response: Thank you for your comment. **The drafting team revised the Applicability of this Standard to address your and others' comments, it now reads: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements".**		
CenterPoint Energy	No	The proposed term for Interconnected Facilities, shown on page 2 of 27 of PRC-027-1

Organization	Yes or No	Question 2 Comment
		Draft #1, is defined as “BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities.” CenterPoint Energy believes Interconnected Facilities should be defined in reference to NERC registration and recommends changing the definition to “BES Facilities that are electrically joined by one or more Element(s) and are owned by different registered entities.”
Response: Thank you for your comment. **The drafting team considered this option; however, the drafting team felt that ‘registered entities’ would potentially mislead some entities that have different functional registrations, to think that the Standard does not apply to them. The term Interconnected Facilities has been changed to Interconnected Element as follows: “An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity”.**		
Dominion	No	
Southwest Power Pool NERC Reliability Standards Development Team	No	
National Grid USA / Niagara Mohawk	No	
Pepco Holdings Inc. & Affiliates	No	
Luminant	No	
Imperial Irrigation District (IID)	No	
Bonneville Power Administration	No	

Organization	Yes or No	Question 2 Comment
Santee Cooper	No	
Detroit Edison	No	
Western Small Entity Comment Group	No	
SERC Protection and Control Subcommittee	No	
Associated Electric Cooperative, Inc., JRO00088	No	
Southern Company	No	
Salt River Project	No	
Operational Compliance	No	
Pacific Gas and Electric Company	No	
Western Area Power Administration	No	
Independent Electricity System Operator	No	
American Electric Power	No	
Sacramento Municipal Utility	No	

Organization	Yes or No	Question 2 Comment
District		
Flathead Electric Cooperative, Inc.	No	
ExxonMobil Research & Engineering	No	
City of Austin dba Austin Energy	No	
Texas Reliability Entity	No	
Manitoba Hydro	No	
Xcel Energy	No	
Tacoma Power	No	
Ameren	No	
Public Utility District No. 1 of Snohomish County	No	
Georgia Transmission Corporation	No	
Platte River Power Authority	No	
MWDSC	No	

Organization	Yes or No	Question 2 Comment
Portland General Electric Company	No	
mason	No	
ATCO Electric	No	
Illinois Municipal Electric Agency	No	
El Paso Electric Company	No	
Trans Bay Cable	No	
Duke Energy	No	
Clark Public Utilities	No	
Oncor Electric Delivery Company LLC	No	
South Carolina Electric and Gas	No	
El Paso Electric	No	
Hydro One	Yes	1. This is related to our comments from Question 1. We believe that the Planning Coordinators (PC) shall be included. PCs are accountable to conduct studies to determine critical clearing times, stable and unstable power swings, etc., to determine coordination. Transmission and Generator Owners do not have access to such information or the

Organization	Yes or No	Question 2 Comment
		tools/experience to conduct such studies. In addition to this there is a possibility that the entity in charge of day-to-day operation of the Interconnection Facilities (likely registered as TOP only) doesn't own the facility and consequently is not registered as a TO. In this case, such facility or the facilities would be out of scope of this standard. We believe that the SDT should refine the Applicability section to encompass the above mentioned cases. 2. From a reliability point of view, we think that this standard should not be applicable to Distribution Providers because the TO is mostly responsible of coordination of the protection with the DP.
Response: Thank you for your comment. **1. The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, if PC is providing such a service it would be by agreement with the Owner, and does not change the fact the Owner has the responsibility.** **2. The drafting team believes Distribution Providers that own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners.**		
ISO RTO Council SRC	Yes	Depending on the intent of the requirements as questioned in the comment to question #1, it may be necessary to include planners to provide data for contingent and varying operating conditions to coordinate relays beyond those dedicated to intertie facilities.
Response: Thank you for your comment. **The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, the fact that the planners may be providing some data necessary to complete the evaluation it does not warrant including them in the Applicability.**		

Organization	Yes or No	Question 2 Comment
GP Strategies	Yes	1. We agree that there should be a process for ensuring that the industry continuously evaluates the system and ensures that the relay settings are coordinated and adjusted to meet the dynamically changing grid. However, we disagree that the studies should be conducted by the owners of the facilities. We feel these studied should be conducted by the Transmission Planner or Planning Authority and the cost of the studies should be allocated equally to all users of the grid. Currently, a study is performed when a new facility is added or an existing facility is modified. Typically, the study is conducted by the Transmission Planner as identified in FAC-002 and paid for by the facility that is being modified or is being added. It makes since that these facilities pay for the studies as they are the ones modifying the overall grid and benefit from the modification. In this case the cost should not be barred by an existing facility. 2. The drafting team states that an owner should perform a study when the fault current changes by 10% or greater at their Interconnected Facility. The team may not have taken into account the potential that these changes are not related to that particular facility but rather from a change in the overall dynamics of the grid. For example, an influx of renewable resources (both behind and in front of the meters), retirement of generation, changes to transmission, or changes in load pockets. In addition, it excludes any new facilities added since 2007 from sharing the cost of changes to the grid. The cost for studies conducted for changes to the existing grid should be allocated to all interconnected facilities and should be performed by the Transmission Planner. As defined in the Rules of Procedure, section 500, the Transmission Planner is "the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area." The Planning Authority is the entity that maintains the information required for the studies and is the entity that could perform the studies at the lowest cost. The cost for performing the studies should be allocated to all entitles doing business on the grid and the cost should be reviewed in a rate case and allocated appropriately.MOD-010 and MOD-012 already provides a requirement

Organization	Yes or No	Question 2 Comment
		to provide the characteristics for system studies to the RRO for updating the models that would be used to conduct the studies. 3. These Standards, however, have a gap in that they do not include Distribution Provider as indicated in the proposed PRC-027 Standard. We recommend the drafting team revise MOD-010 and MOD-012 to retrieve all necessary information to update the RRO model and that the Transmission Planner be tasked with performing the necessary studies.
Response: Thank you for your comment. **1. The studies conducted by the Transmission Planner or Planning Authority related to FAC-002 are not necessarily directly related to the protection system study identified by this standard. The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, if the Transmission Planner or Planning Authority is providing such a service it would be by agreement with the Owner, and does not change the fact the Owner has the responsibility. It is also noted that Protection System Studies are not generally conducted by the Transmission Planner or Planning Authority.** **2. The observation that changes to the grid not directly associated with the Interconnected Element(s) is exactly the driver for the inclusion of a regular review of fault currents at the Interconnected Element(s). If such changes result in a 10% change in the conditions that were used in the last Protection System Study, the need for a new study must be evaluated; however, it does not require a study be done.** **3. Modifications of the noted standards are outside the scope of this drafting team.**		
Idaho Power Company	Yes	Yes, Transmission Operators may own protection systems but not the interconnected element due to cost sharing agreements among Entities, for example. The applicability should be expanded to cover the Entity responsible for operation of the protection system element and interconnection.
Response: Thank you for your comment. **Based on the Functional Model, the drafting team does not see how the Transmission Operator would own Protection Systems without also being registered as a Transmission Owner. If such a scenario does exist, it is assumed that it would be by agreement**		

Organization	Yes or No	Question 2 Comment
with the Owner, and does not change the fact that the Owner has the responsibility.		
Exelon	Yes	Agree, all entities should be included if they are responsible for engineering of protection systems protecting BES elements at Interconnected Facilities.
Response: Thank you for your comment. **It is unclear to the drafting team which additional entities are being suggested for inclusion.**		
Public Service Enterprise Group	Yes	Within RTOs and ISOs, entities such as PJM and NYISO perform such evaluations as part of their transmission planning process. See PJM Manual 14-B, Appendix G, section G.7 which states: "PJM performs short circuit analysis as part of the annual Regional Transmission Expansion Plan (RTEP) baseline assessment. This analysis includes a study of the entire PJM system based on its current configuration and equipment." Therefore, Transmission Planners should be considered as an applicable entity for R2 as discussed in #9 below
Response: Thank you for your comment. **The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, if the RTO or ISO is providing such a service it would be by agreement with the Owner, and does not change the fact the Owner has the responsibility.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	Yes	It would seem like Transmission Planners and Planning Coordinators would have a natural interest in modifications made to relay systems. Their simulations must show that BES performance under various contingencies meets certain criteria. Any information discovered in the course of the Protection System Studies would be of interest to them as well.
Response: Thank you for your comment. **The drafting team agrees; however, the Protection System data that may need to be provided by the owner to the Transmission Planners and Planning Coordinators is covered by other Standards.**		

Organization	Yes or No	Question 2 Comment
TransAlta Centralia Generation LLC	Yes	The applicability should include other functional entities which should provide power system study data.
Response: Thank you for your comment. **It is unclear to the drafting team which additional entities are being suggested for inclusion.**		
Liberty Electric Power LLC	Yes	
NV Energy	Yes	
ACES Power Marketing Standards Collaborators	Yes	

3. **In Requirement R1, the SDT allowed a responsible entity 36 months to have a documented Protection System Study completed for each Interconnected Facility if the responsible entity does not already have a Protection System Study for that Interconnected Facility performed on or subsequent to June 18, 2007 (the effective date of PRC-001-1). Do you agree with this time frame? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Many commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Elements enough time to complete the Protection System Studies, and that there is no evidence there is widespread miscoordination between Interconnected Stations; therefore, the drafting team changed the time frame to forty-eight months.

Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2.

Several commenters stated that the definition of Interconnected Facility is confusing. The drafting team changed the term to Interconnected Element defined as follows: “An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity”.

Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).”

Organization	Yes or No	Question 3 Comment
Pepco Holdings Inc. & Affiliates	No	1. Each owner should already possess information demonstrating that their protective devices are set to “coordinate” with adjacent protection systems. However, the documentation that presently exists may not be in the form of a formal “coordination study” in a format suitable for audit purposes. Some guidance should be provided indicating what form of documentation is expected,

Organization	Yes or No	Question 3 Comment
		especially by the TO. For instance, on transmission tie lines between different TO's coordination of zone distance elements is fairly straightforward and can be accomplished without a traditional "coordination study". Also settings on pilot schemes need to be exchanged in order to allow for proper operation, but this is also not what is considered a traditional "coordination study". On the other hand, coordination between GO's and TO's is even more complicated. Without some direction as to what specific documentation is required it is difficult to estimate how many existing interconnection points would have to be re-visited in order to produce the required auditable documentation. 2. Some specific examples of what specific type of documentation is required would be helpful. To be safe, most likely all interconnection points would be revisited to ensure adequate compliance documentation. Also, for each revised Protection Study produced (per R1.1) a formal review (R1.2) and approval (R4.1) would be required. 3. As such, with the large number of interconnection points on the system a 60 month time frame would be more appropriate. The SDT acknowledged that they had no evidence that there is widespread miscoordination between Interconnected Facilities when establishing the arbitrary 36 month requirement.

Response: Thank you for your comment.

1. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2.**

2. **Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."**

Organization	Yes or No	Question 3 Comment
3. Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists.		
Hydro One	No	1. Hydro One would like to suggest that 60 months would be a more realistic span of time needed in order to formally complete a documented study, or derive a time frame based on the number of interconnections that an entity must conduct studies for. Whether the systems are co-ordinated or not, the work needs to be carried out and documented. In the case of Hydro One there are almost 300 individual generator connections that belong to other entities many of whom do not have onsite protection experts. Most of these connections do not have a formal documented protection co-ordination study. 2. Statements in R1.1.2 and 1.1.3: "unless the entity can demonstrate such a study is not required." and its corresponding measure: " or documentation demonstrating why a study is not required for changes described in Parts 1.1.2 and 1.1.3" are vague and don't give much guidance on what would be the appropriate evidence in this case. 3. Suggest adding examples of documents that can be used to demonstrate compliance.
Response: Thank you for your comment. **1. Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Elements. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element**		

Organization	Yes or No	Question 3 Comment
exists" 2. Based on your comment, the drafting team revised Requirement 1, Parts 1.1.2 and 1.1.3 to include the phrase: "or technically justify why such a study is not required". As stated in the Rationale box for Part 1.1.2, one example of a technical justification would be: "when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current". 3. Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."		
Bonneville Power Administration	No	1. This question assumes that the requirement to perform a protection system study is acceptable, and the question focuses only on the timeframe allowed. In BPA's opinion, the requirement to have a protection system study is objectionable and cause for disapproval of the standard. Therefore, the timeframe is irrelevant. 2. In addition, the standard fails to make clear just what a protection system study is, either in the definition, the requirements, or the guidelines that follow. BPA believes that R1 is ambiguous and unacceptable.
Response: Thank you for your comment. 1. The drafting team believes that documentation is necessary in order to have a record that the coordination study was completed, communicated to the appropriate Entities and agreed upon. 2. The drafting team made various changes including those to the definition, requirements, and guidelines to clarify what a Protection System Study is. Other commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system		

Organization	Yes or No	Question 3 Comment
Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."		
FirstEnergy	No	Requirement 1, Part 1.1.1 - Although we agree with the timeframe, the phrase "within 36 calendar months after the effective date . . . . subsequent to June 18, 2007" should not be listed as a requirement but rather as part of the Implementation Plan.
Response: Thank you for your comment. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."**		
Detroit Edison	No	Why aren't studies performed prior to June 18, 2007 considered acceptable if they're still valid as long as no significant fault current or system changes have occurred?
Response: Thank you for your comment. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2. which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."**		
MRO NSRF	No	1. If an entity has a Protection System Study performed prior to June 18, 2007 that

Organization	Yes or No	Question 3 Comment
		meets the requirements for the study specified in PRC-027-1 and there have been no changes to trigger a new study as specified in PRC-027-1 (that have occurred) the study should be acceptable for compliance with the standard. It is suggested that the requirement R1, sub-requirement R1.1 be revised by removing the phrase "that was performed on or subsequent to June 18, 2007." 2. The NSRF questions if 36 months is ample enough time for large company to get all studies done within 36 months. Unless R1.1 is revised to mean all studies regardless to when it was performed.
Response: Thank you for your comment. 1. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."** 2. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Elements. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**		
PPL Corporation NERC Registered Affiliates	No	As noted in the response to question #1, TOs and DPs have the data and the capability needed to perform the studies that appear to be contemplated by the SDT.
Response: Thank you for your comment.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td colspan="3">The drafting team agrees.</td></tr>
<tr><td>Tennessee Valley Authority</td><td>No</td><td>1. "Protection System Study" is a new term being introduced with this standard. Since industry documentation of protection system coordination reviews are conceivably available from both before and after June 18, 2007, precluding coordination reviews performed prior to June 18, 2007 from acceptable compliance evidence could greatly increase the workload of protection system engineers during the proposed 36 month time period. Note that there is a possibility of overlap with the "Order 754 request for data" response period. The rationale statement for R1, Part 1.1.1, indicates that the effective date of PRC-001-1 was the basis for selecting June 18, 2007. PRC-001-1 primarily addresses new protective systems and changes (R3 & R5) and coordination with neighboring GOP, TOP and BA entities (R4). We suggest changing the wording of Part 1.1.1 to the following: “Within 36 calendar months after the effective date of this standard, if no valid Protection System Study for that Interconnected Facility exists.”</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).</td></tr>
<tr><td>ACES Power Marketing Standards Collaborators</td><td>No</td><td>(1) Conceptually, we agree with the intent of the standard and this requirement as it is presented in the application guidelines. However, more refinement is needed to make this requirement implement what is explained in the application guidelines. For instance, nowhere in Requirement R1 is it stated clearly that the responsible</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		entity is only responsible for performing Protection System Studies (PSS) for only those breakers it owns and are protecting the Interconnection Facility. This is pretty clear in the application guidelines. (2) While we do not disagree with the time frame, we question if it should be part of the requirement. It makes more sense to include the time frame for initial compliance of a requirement in the implementation plan. In that way, the initial compliance time frame does not persist in the standard long after it is no longer needed. It is common to utilize the implementation plan to describe initial compliance dates. Furthermore, FERC approves implementation plans as part of the standards package so there is no issue with whether the implementation plan is enforceable. (3) We disagree with limiting PSS that can meet this requirement to only those that occurred after June 18, 2007 as defined in Part 1.1.1. While NERC cannot compel evidence from a date before the standards became enforceable, there is no reason that a TO, GO, or DP could not choose to utilize a PSS from before this date as evidence. (4) We think the use of PSS in Part. 1.1 is partly redundant to the definition. The definition indicates PSS is a study that demonstrates Protection Systems operate in desired sequence for clearing Faults. Part 1.1 states that the TO, GO, and DP shall perform the PSS "to verify Protection Systems remove from service only those Elements required to isolate Faults" are removed from service. Isn't the statement in Part 1.1 "to verify Protection Systems remove from service only those Elements required to isolate Faults" equivalent to the demonstrating that Protection Systems operate in the desired sequence for clearing faults as defined in the PSS? (5) We disagree with including the Distribution Provider in this requirement. The primary reason that a Distribution Provider owns Protection Systems that protect Interconnected Facilities is that it is often cheaper to install a fault interrupting device and its associated Protection Systems on the distribution side. These Protection Systems are typically installed per the Transmission Owner facility connection

Organization	Yes or No	Question 3 Comment
		requirements which are established per FAC-001. The Transmission Owner usually still performs the PSS and short circuit study and the Distribution Provider uses settings specified by the Transmission Owner. The fact that FAC-001 applies only to the TO and allows the TO establish such facility connection requirements that applies to the DP further supports this claim. (6) The definition of Interconnection Facility is confusing and needs further refinement. First, we are not sure what the purpose of including “that are electrically joined by one or more Element(s)” is. If it is not electrically joined, it cannot be a Facility. It would not be part of the BES which is a basic requirement of the Facility definition. Second, it is not clear if this is intended to cover only jointly owned Facilities or not. We do not think that is the intention but the clause “are owned by different functional, operating or corporate entities” cause this confuses. Third, ownership cannot be defined by functional or operating entities. A corporate entity may be registered as a TO and GO. Which part of the definition applies for the interconnection between the transmission system and generator: Functional Entities or Corporate Entities? Furthermore, a functional entity or operating entity does not really describe a legal entity capable of ownership. The definition of Interconnected Facility should be a Facility that ties together two different sets of Facilities together where the Protection System coordination would be performed by different companies. This would appear to be consistent with the explanation of the standards in the application guidelines. For example, a Facility connecting two different TO transmission systems together where the TOs are owned by separate corporate entities would be an Interconnected Facility. A generation interconnection Facility would only be considered an Interconnection Facility if the GO and TO were separate corporate entities. If they were the same corporate entity, coordination would already occur and the generation interconnection Facility should not be considered an Interconnected Facility.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
1. **The drafting team believes that the Entity is responsible for conducting the PSS as described in the application guidelines.** 2. **Making the time frame part of the Requirements was the choice of the drafting team.** 3. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2.** 4. **Several commenters stated that the definition of Interconnected Facility is confusing. The drafting team changed the term to Interconnected Element defined as follows: Interconnected Elements: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".** 5. **The Applicability of this standard includes Protection Systems installed for the primary function of detecting Faults on BES Elements irrespective of what functional entity owns them. Protection Systems not installed for the primary function of detecting Faults on BES Elements are not included in the Applicability.** 6. **Several commenters stated that the definition of Interconnected Facility is confusing. The drafting team changed the term to Interconnected Elements defined as follows: Interconnected Elements: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".**		
Kansas City Power & Light	No	The protective systems were coordinated when installed. If the power system has not undergone any significant change, then line impedances and fault current levels are the same and the original settings are still valid. So, no new study is required based on the passage of time. A new study is needed only if there have been significant system changes as outlined under question 5 and requirement R3.Requirement 1.1 states each entity must perform a system protection coordination study, however, the coordination efforts will be joint efforts between the entities and sharing of pertinent information such that an effective study can be performed. The proposed Standard should make it clear the study effort can be a joint study between the entities involved and that independent studies are not necessarily intended by each entity.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
The drafting team acknowledges that the identified Protection System Studies can be a joint effort but believes they do not have to be. The drafting team agrees with the concept of joint studies as long as all involved entities have the required documentation.		
Southern Company	No	60 months would be more reasonable for those that have a large number of generators and/or interconnections. Perhaps a tiered approach: 36 months for those with less than 50, 60 months for those with more than 50 but must have 50% done within 36 months?
Response: Thank you for your comment. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**		
Salt River Project	No	The requirement to provide a copy of each Protection System Study is an administrative burden that does not reflect the intent of Results Based Standards. Changing the requirement to maintain evidence that Protection System Studies are coordinated and affected entities have agreed to the results of the Studies is adequate.
Response: Thank you for your comment. **The drafting team is not requiring a Protection System Study; only a summary of the results of the Protection System Study performed is required to be provided to the other entities.**		
Pacific Gas and Electric Company	No	PG&E we believes that the 6 calendar month time frame in requirement R1.1.2 is too short and should be extended to 12 calendar months
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
The drafting team believes because fault current reviews are conducted every 2 years, the expectation is that the number of instances where the fault current changes by 10 % will be limited. We therefore believe that the 6 month time frame is appropriate and decline to make the suggested change.		
American Electric Power	No	1. 36 months is not adequate for unique Protection System Studies to be conducted for the TO, GO, and DP. The interface and coordination requirements as written will require close communication with a vast number of interconnected facilities. In addition the generation landscape changes over the next few years with the large number of generation retirements and additions will continually change the short circuit model. AEP believes that these contributing factors will lead to time requirements above the proposed 36 months currently in the standard. AEP would require a minimum of 60 months to complete this work as the AEP system exists today. An added complication that will impact this time requirement is the approval of FERC Order 1000, which could result in additional interfacing TO's inside AEP's footprint. In addition, NERC's rationale for R1 states that "the SDT has no evidence there is widespread miscoordination between Interconnected Facilities that warrants a shorter time frame." If this is the case, then there should be no issue with extending this timeframe. 2. Using the word "demonstrates" within the definition for Protection System Study could be interpreted as requiring an actual, operational test rather than a simulation study. We recommend changing the definition to "a study that demonstrates that the existing or proposed Protection System design will enables the Protection System to operate in the desired sequence for clearing Faults." 3. Is using the defined term "Protection System" appropriate? Does it possible bring things into scope (CTs, PTs, Station batteries) which should not?
Response: Thank you for your comment. **1. Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations**		

Organization	Yes or No	Question 3 Comment
enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists". 2. The definition of Protection System Study refers to "a study that demonstrates"; consequently, the drafting team believes the word "demonstrates" is appropriate in the context it is used. 3. As stated, the Protection System does include CTs and VTs which are part of the considerations used when determining the settings of a protective relay. The information needed to be transmitted to another Entity would include this equipment.		
Sacramento Municipal Utility District	No	There is no need to have a Protection System Study available for review for every Interconnected Facility. The study is useful only as an intermediate product that leads to relay settings and as a basis for both entities to agree that their planned settings will coordinate. The results based objective is that the registered entities communicate and coordinate together. A simple statement by both entities that they have reviewed each other's settings and agree they coordinate is sufficient proof that the reliability objective of this standard has been met.
Response: Thank you for your comment. **The standard requires a Protection System Study be performed but only requires a summary be provided to the other entity. The standard provides for documentation of the agreement which may be a simple statement as you indicate.**		
Idaho Power Company	No	1. No, Should a Protection System Study under R1 result in triggering of the other Requirements in the Standard, more time may be needed. 2. An Entity could easily find themselves responding to multiple inquiries from Interconnectors while performing their own Studies. Additional time should be allowed to address the results of the Protection System Studies triggered during this implementation timeframe.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. **1. The Requirement R1 time frame only addresses performing a Protection System Study; this time frame is not inclusive of other changes that may result from the Protection System Study and are covered by Requirements R3 and R4.** **2. The time frame for Requirement R1 has been increased to forty-eight months and the drafting team believes this time is sufficient to perform all required studies.**		
Exelon	No	Exelon cannot agree to the time frame proposed without understanding the scope of work involved in the required protection system study. 1. The current definition of Protection System Study (PSS) is not clear enough to avoid confusion. To better define the "study" as referenced in PRC-027-1 and to ensure that applicable entities know what they're required to do, the definition of PSS needs to clarify the elements of the protection system and power system conditions the study is run similar to how required Transmission Planning studies are defined. With this in mind, Exelon suggests the following definition for "Protection System Study": A study that demonstrates that existing or proposed Protection Systems operate in the desired sequence for clearing a fault. The study is conducted with a single power system element out of service and all Protection System elements in service, and with all power system elements in service and a failure of a single protective relay, communication system, ac current input, ac voltage input, or DC control circuit (these can be further defined using the information and Table from Order 754). 2. Exelon suggests that "summary results of a protection system study" should also be defined with clear parameters established. Unless the specific particulars are established, Exelon predicts that there will be confusion as auditors attempt to decide whether or not a piece of evidence will qualify as a "summary" of a Protection System Study. This is similar to the ambiguity in the existing revision of PRC-005-1 R1.2 which requires a "summary" of maintenance and testing procedures, yet does not describe specifically what is required. It is our experience that registered entities and auditors historically have had differences

Organization	Yes or No	Question 3 Comment
		of opinion about what constitutes a “summary”.
Response: Thank you for your comments. 1. Based on your comments and others, the drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).” Additionally, language has been included in the Guidelines and technical Basis section of the standard to indicate “System conditions used in Protection System Studies include maximum generation and transmission system at normal operating conditions and under single contingency conditions.” 2. Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).”		
Liberty Electric Power LLC	No	I disagree with the requirement for a protection system study. From the draft standard: "The SDT has no evidence there is widespread miscoordination between Interconnected Facilities". There are approximately 18,000 generators in the US. Requiring each to perform a system study would result in costs running into the hundreds of millions of dollars. This will result in lower BES reliability as entities transfer funds from other reliability efforts to comply with this standard.
Response: Thank you for your comment. **The drafting team believes the requirements of this standard will enhance the reliability of the BES.**		
Public Utility District No. 1 of	No	Comments: There is no need to have a Protection System Study available for review

Organization	Yes or No	Question 3 Comment
Snohomish County		for every Interconnected Facility. The study is useful only as an intermediate product that leads to relay settings and as a basis for both entities to agree that their planned settings will coordinate. The results based objective is that the registered entities communicate and coordinate together. A simple statement by both entities that they have reviewed each other's settings and agree they coordinate is sufficient proof that the reliability objective of this standard has been met.
Response: Thank you for your comment. **The standard requires a Protection System Study be performed but only requires a summary be provided to the other entity. The standard provides for documentation of the agreement which may be a simple statement as you indicate.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	No	1. This requirement assumes that a material percentage of the many thousands of interconnecting relay systems have a problem. There is no evidence of this; and in fact, the Rationale text box for R1 states that the converse is true. This makes sense, as the inter-operation of Fault isolation Protection Systems is a fundamental and well-understood concept - which may not be the case with the more complex relay types. In our opinion, the two-year TO assessment will be sufficient to catch an issue and drive improvements afterwards. Therefore requirement R1.1.1 should be deleted. 2. In addition, we do not agree with the "on or subsequent to June 18, 2007" time frame, since these studies are completed when a facility is built, and/or when a facility is significantly changed, which could quite possibly be prior to 2007. If studies were completed before June 18, 2007, and nothing significant has changed, the study meets the PRC-027 requirement, and/or the TO assessment does not indicate a need, there is no purpose served by repeating the study.
Response: Thank you for your comment. **1. For entities that do not have a Protection System Study as specified in Requirement R1 will need to conduct a study to create a baseline for use in the two year TO assessment as outlined in Requirement R2.**		

Organization	Yes or No	Question 3 Comment
2. Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2.		
Wisconsin Electric Power Company	No	1. In some cases there may be many Interconnected Facilities between two or more owners. It cannot be expected that owners will be able to support performing multiple studies in parallel, at the same time. It would be best to eliminate the specified timeframe, and allow the owners the latitude to determine the timeframe based on priorities decided by them. 2. Also, replace the phrases in R1.1.2 and in R1.1.3, "... unless the entity can demonstrate such a study is not required", with "unless the entities involved agree that a study is not required". If the interconnected entities agree that a study is not required, there should be no requirement to document the reasons why a study is not required. Likewise, revise M1 to include as acceptable evidence "documentation that the relevant entities have agreed that a study is not required."
Response: Thank you for your comment. **1. The time frame for Requirement R1 has been increased to forty-eight months and the drafting team believes this time is sufficient to perform all required studies.** **2. The drafting team revised Requirement 1, Parts 1.1.2 and 1.1.3 to include the phrase: "or technically justify why such a study is not required". As stated in the Rationale box for Part 1.1.2, one example of a technical justification would be: "when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current". Documentation is needed to verify that an agreement was reached.**		
NV Energy	No	With such a long time frame for conducting this subject study, one cannot assure that the protection systems are coordinated, and there could be an impending mis-coordination that goes uncorrected. Suggest 12 or 24 months.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".		
Dairyland Power Cooperative	No	It is agreed that the there needs to be a time period for Protection System Studies to be performed after the standard takes affect. However, the length of time is a concern due to the industries existing resources. It would be preferred that the time period be lengthened to 60 months.
Response: Thank you for your comment. **Many of the commenters suggested that 36 months was not enough time – suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**		
Platte River Power Authority	No	There is no need to have a Protection System Study available for review of every Interconnected Facility. The results based objective is that the registered entities communicate and coordinate. a simple statement by both entities that they have communicated and coordinated is sufficient.
Response: Thank you for your comment. **The standard requires a Protection System Study be performed but only requires a summary be provided to the other entity. The standard provides for documentation of the agreement which may be a simple statement as you indicate.**		
MWDSC	No	1. Protection Systems installed prior to June 18, 2007 should not be required to redo

Organization	Yes or No	Question 3 Comment
		a study because a system study should have been performed prior to installation based on the interconnected configuration at that time. The interconnected systems will change over time and redoing studies will raise more questions on assigning responsibility for changes beyond the control of the protection system owner. 2. For protection systems installed prior to June 2007, TOs should only be required to show a study was performed and coordinated with appropriate interconnected entities.
Response: Thank you for your comment. **1. Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."** **2. A valid Protection System Study will require the same documentation, regardless of the date of completion.**		
American Transmission Company	No	1. ATC does not agree with the time frame proposed. 2. The existing requirements in PRC-001 do not require protection system studies with Distribution Providers. As such, even though studies have been completed there may be no package (documentation) to support an audit. This requirement assumes that, if there is no existing fault study, one needs to be completed. If there have been no changes in short circuit or protective schemes, allow for completion of the studies based upon prioritization using voltage class and loading level.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
1. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists"** 2. **The drafting team modified Requirement R1, Part 1.1.1 to make studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."**		
NPPD	No	To mitigate compliance risks for various types of data formats for existing studies and studies older than June 2007 this standard will likely require utilities to go back and update all data so that it meets the requirements and description of evidence in the application guidelines when the requirements become enforceable. This could likely take longer than 3 years. I would recommend more time such as 6-10 years (time depends on the number of applicable system ties as well)
Response: Thank you for your comment. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**		
CenterPoint Energy	No	(a) The proposed term for Protection System Study, shown on page 2 of 27 of PRC-027-1 Draft #1, is defined as "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults." CenterPoint

Organization	Yes or No	Question 3 Comment
		Energy recommends Protection System Study instead be defined as “A study that demonstrates Protection Systems operate as desired for clearing postulated short circuit Fault events.” (b) CenterPoint Energy believes a 36 month implementation to have a documented Protection System Study completed for each Interconnected Facility is overly burdensome, unless certain Interconnected Facilities are exempted. CenterPoint Energy recommends exempting Interconnected Facilities that are serving only load and that are connected by no more than two transmission line Elements that are operating between 100 kV to 200 kV. Many of these Interconnected Facilities have fault-proven, time-proven protection system set points. Additionally, Draft #1, on page 5 of 27, notes that protection system misoperations related to coordination issues are addressed by PRC-004.
Response: Thank you for your comment. a. **The definition of Protection System Study refers to “a study that demonstrates”; consequently, the drafting team believes the word ‘demonstrates’ is appropriate in the context it is used.** b. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: “Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists”.**		
NextEra Energy Inc	No	While 36 months is allowed for studying all interconnections, what time is allowed for mitigation of identified setting or hardware change? If an issue is discovered, then an additional 12-24 months mitigation time should be allowed.
Response: Thank you for your comment. **The Requirement R1 time frame only addresses performing a Protection System Study; this time frame is not inclusive of other**		

Organization	Yes or No	Question 3 Comment
changes that may result from the Protection System Study and are covered by Requirements R3 and R4.		
Oncor Electric Delivery Company LLC	No	Given the “agreement” requirements defined in Requirement R4 and the uncertainty of its interpretation, many of the recent protection system studies may have to be performed again. Therefore, a more appropriate timeframe would be 5 years to have all applicable Protection System Studies completed.
Response: Thank you for your comment. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: “Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists”.**		
Western Area Power Administration	No	
ExxonMobil Research & Engineering	No	
National Grid USA / Niagara Mohawk	Yes	As a TO our experience has been that many GOs do not reply to requests for information. If the 36 month window cannot be met by a TO because information requests are ignored what recourse does the TO have to avoid a penalty for non-compliance?
Response: Thank you for your comment. **Requirement R3, Part 3.2 specifies that the “Requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 calendar days of receiving a request or according to an agreed-upon schedule.” In your example, the GO would be in violation of this standard.**		

Organization	Yes or No	Question 3 Comment
Associated Electric Cooperative, Inc., JRO00088	Yes	AECI objects with the line of questioning here, because it does not fully address all aspects of Requirement R1. While AECI appreciates the 36 month time-frame, we did receive internal comment back from our planning engineers Relay Operations Sub-Committee: 1) Concerning our Regional Entity's Short Circuit Data Working Group, the current status is such that a unilateral AECI SC study would be technically difficult. 2) Further, significant modeling development will be necessary in order for entities to comply with this requirement through a regional study formation, i.e. 3 yrs is a definite push on the timeline on the Initial pass. 3) Finally, the information to be reported from a Protection System Study R1.1, and particularly the information to be communicated to other entities R1.2, may be too vague. This primary concern is for personnel being inundated by the sheer volume of data that can now be performed in relation to such studies. AECI would appreciate the SDT providing further Industry Guidance as to what would constitute a clear and concise set of information, to be transmitted or received from corresponding parties.

Response: Thank you for your comment.

1. **The drafting team believes that a short-circuit study is required to meet the requirements of this standard and acknowledges that this is a collaborative effort.**
2. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**
3. **Requirement R1.2 has been modified to include additional details for the summary of results as follows: "or technically justify why such a study is not required".**

Organization	Yes or No	Question 3 Comment
Flathead Electric Cooperative, Inc.	Yes	This seems like an adequate time, but it is unclear that smaller transmission dependent utilities really need to do this to maintain reliability and if their ratepayers would see any reliability benefit.
Response: Thank you for your comment. **This standard is applicable to Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.**		
LCRA Transmission Services Corporation	Yes	Requirement R1 should read as follows:"Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System shall: "Requirement R1.1.2 should read as follows: Within 6 calendar months after determining or being notified of a change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.
Response: Thank you for your comment. **1. In the case where different portions of the Protection System are owned by different entities, then the Protection System Study must be a collaborative effort.** **2. The drafting team revised Requirement 1, Part 1.1.2 to include the phrase: "or technically justify why such a study is not required".**		
Xcel Energy	Yes	The standard does not specify M2 violation reporting responsibility or assignment of violation due to non-responsiveness of the interconnected entity. Clarification needs to be made as to what is considered acceptable evidence that the affected entity received the study results under measure M2. Would a registered mail confirming receipt at an address be considered acceptable evidence; if not what type of document service would be considered acceptable?

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. **Registered mail confirming receipt at an address would be considered acceptable evidence. Additional acceptable evidence would be letters, or emails acknowledging receipt.**		
Public Service Enterprise Group	Yes	We do not believe this requirement has been justified for the several reasons listed below. In addition, the "Protection System Study" definition is too vague as to what it should include. We suggest a separate appendix that lists the items that this study should address. We also suggest that the SDT develop several baseline and change case Protection System Study examples, using a common format. These should be incorporated into an appendix within the standard. a. The format and overall purpose of the baseline study has not been provided. It is highly unlikely that a sufficient Protection System Study has been completed or is available for a majority of the Interconnected Facilities since 6/18/2007 within North America. This is due in part to either no modifications being performed at these facilities or lack of data retention (a study was performed but since it was not a requirement, documentation is not available). To require entities to now perform such studies would be a sizeable undertaking and create a tremendous burden to all entities with little benefit to the entities and the reliability of the BES. For older Interconnected Facilities where no changes have been made in several decades, no benefit to the facility or the BES would come from perform such a study. b. The only time a Protection System Study should be performed is when a driver is in place that will require a possible relay setting changes. These drivers should be spelled out specifically. For example, if there is substation project work that requires relay setting changes, if the relays are being replaced, if a "tie line" is being re-conductored, etc. The requirement to perform a study should also apply to those "interface" relaying schemes that would normally require periodic review. The requirement for a periodic review will be driven by something other than a system configuration change. This may include schemes that have current operated relaying

Organization	Yes or No	Question 3 Comment
		where the setting of the relay is dependent of fault current level. c. The complexity of such a study is uncertain. In most cases, the “interface” relaying between two TO’s or a TO and a GO is very straightforward. In the case of the “interface” between a TO and a GO, the relaying may simply be a transformer differential scheme. In the case of a tie line between two TOs, if the relaying is strictly impedance based, then there is no need to perform a baseline study. In other cases, the study may be more complex. The study may also have to incorporate Protection System devices beyond the Interconnected Facility (e.g. BOP protection for generators, adjacent line or bus protection for transmission facilities). This would increase the amount of time and complexity required to perform the study. How would the SDT define the appropriate protection coordination boundaries for an Interconnected Facility?

Response: Thank you for your comment.

a. **Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).” Entities that do not have a Protection System Study as specified in Requirement R1 will need to conduct a study to verify Protection System coordination and to create a baseline for use in the two year TO assessment as outlined in Requirement R2.**

b. **Requirements R2 and R3 provide the triggering points that indicate when a new study is necessary.**

c. **The drafting team acknowledges that the complexity of the Protection Systems applied will determine the scope of a Protection System Study and in some cases may not be required; however, this does not preclude the need for a baseline study. Application Guidelines provide examples of the protection boundaries.**

Organization	Yes or No	Question 3 Comment
mason	Yes	Although the timeframe appears reasonable, the more basic question about the necessity of the documentation requirements needs to be reconsidered.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. The drafting team believes that documentation is necessary in order to have a record that the coordination study was completed, communicated to the appropriate Entities and agreed upon.		
Duke Energy	Yes	However R1 is confusing by having two sub-requirements R1.1 and R1.2, two measures M1 and M2, and VSLs consisting of various combinations of non-compliance with sub-requirements. We think it could be made clearer by separating R1.2 out as a separate requirement with its own measure and VSLs. We have made a similar comment on Question 8 that other requirements, measures and VSLs in this standard could be made clearer by breaking them apart. Also, Requirement R1.2 states “each affected Interconnected Facility owner” without describing how the owner may be affected.
Response: Thank you for your comment. **The drafting team used the format recommended by NERC staff.**		
Dominion	Yes	
Southwest Power Pool NERC Reliability Standards Development Team	Yes	
Luminant	Yes	
Imperial Irrigation District (IID)	Yes	
Santee Cooper	Yes	
Western Small Entity Comment Group	Yes	

Organization	Yes or No	Question 3 Comment
SERC Protection and Control Subcommittee	Yes	
Colorado Springs Utilities	Yes	
ISO RTO Council SRC	Yes	
Progress Energy	Yes	
Operational Compliance	Yes	
Independent Electricity System Operator	Yes	
City of Austin dba Austin Energy	Yes	
Texas Reliability Entity	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Tri-State G & T	Yes	
Ameren	Yes	
Georgia Transmission Corporation	Yes	
Portland General Electric	Yes	

Organization	Yes or No	Question 3 Comment
Company		
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
El Paso Electric Company	Yes	
Trans Bay Cable	Yes	
Clark Public Utilities	Yes	
South Carolina Electric and Gas	Yes	
El Paso Electric	Yes	

4. In Requirement R2, the SDT established a +/- 10 % change in an Interconnected Facility's Fault current value as a criterion for notifying interconnected entities to give the interconnected entity a "heads up" that a review of the existing documented Protection System Study may be warranted. Do you agree with the +/- 10 % Fault current threshold for initiating this review? If not, please provide an alternative means along with a technical justification for determining a threshold.

Summary Consideration:

A majority of the commenters agreed with the 10% deviation trigger. Of those that disagreed and provided an option, they suggested a range of 15-20%. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows timely notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.

Multiple commenters expressed confusion as to where the fault needed to be applied, what branch(s) needed to be monitored, and what system conditions needed to be considered. Some expressed that the fault should be applied at the bus so that batch studies could be run to automate the short circuit study. The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."

Based on comments, the drafting team reworded Requirement R2 to provide clarity. The requirement now reads: "For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall:"

Several commenters suggested modifying the equation to replace "V" with "I". The drafting team made the change.

Organization	Yes or No	Question 4 Comment
Pepco Holdings Inc. & Affiliates	No	The 10% threshold would be acceptable providing the following changes were made to Requirements R2.1 and R2.2:R2.1 – 1. Re-word Requirement R2.1 to read: "Perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities, not less than once every 24 months. 2. R2.2 - Re-word Requirement R2.2 to read: "Calculate the percent deviation

Organization	Yes or No	Question 4 Comment
		between the maximum available Fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation...” The existing wording requires one to “calculate the percent deviation between the fault current values ... for the bus(s) or Elements(s) under consideration”. 3. Including the phrase “or Element(s) under consideration” increases the complexity of the periodic fault screening requirement significantly. Instead of performing a relatively easy bus fault summary routine (available in most batch short circuit programs) individual branch current in various coordination pairs must be examined. Take for example the system shown in Figure 1 in the Application Guidelines. Instead of just screening the available bus fault current at the point of interconnection (the ownership boundary between the two entities), fault current in each “element under consideration” used in the Protection study must be calculated. This would mean determining fault current flows through breakers A, B, C, D, E, F, G, & H) under various fault scenarios and comparing them to those used in the previous coordination study. This is far from a simple task and not conducive to a “batch” screening tool. The intended purpose of R2.2 is to catch external system changes that have over time led to gradual increases in fault current that may require the Protection System Study to be re-examined. A simple year to year bus fault comparison would serve this purpose. System changes at, or immediately adjacent to, the interconnection point, which could lead to a re-distribution of fault currents through the effected element(s), would be caught elsewhere under R3.1 “Additions, removals, or replacements of transmission Elements”.

Response: Thank you for your comments.

1. **Per your suggestions and others, the drafting team has modified Requirement 2.1 to read “Perform a short-circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus,**

Organization	Yes or No	Question 4 Comment
not less than once every 24 months.” 2. The drafting team believes the existing wording was sufficient and did not make your suggested change. 3. The drafting team did remove the word “or Element(s)” as you suggested.		
Hydro One	No	Hydro One agrees with the need of a defined fault current threshold. However, we’d like to suggest a 20% threshold instead as most protection settings, if coordinated properly, must coordinate with system normal and under credible minimum system conditions, therefore, it is our opinion that a 10 % change should generally not affect coordination.
Response: Thank you for your comment. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.		
Bonneville Power Administration	No	This question assumes that the requirement to perform a mandatory short-circuit study every 24 months is acceptable, and the question focuses only on the percent change of the study results that will require notification. BPA believes that a short-circuit study should not be required and the percent change that triggers notification is irrelevant.
Response: Thank you for your comment. The drafting team believes that a periodic Fault current study is necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.		
Detroit Edison	No	Recommend that the “trigger” be a system change (line, transformer, generator) that

Organization	Yes or No	Question 4 Comment
		results in an impedance change.
Response: Thank you for your comment. **Requirement R3 of this standard allows for system changes to trigger a study as you suggest. However, the drafting team believes that a periodic Fault current study is necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination.**		
Northeast Power Coordinating Council	No	1. Agreed that a change in fault current is a method to trigger a coordination study, but a 15% threshold would be more efficient (+/- 15 %). 2. Clarify where the fault is to be applied and where the deviation is to be observed. One possibility is to apply the fault at a bus at one end of the tie and then determine the deviation in the current in each element connected to that bus.
Response: Thank you for your comments. **1. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.** **2. Per your suggestions and others, the drafting team has modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
PPL Corporation NERC Registered Affiliates	No	See comment in question #1 above.
Response: Thank you for your comment. **Please see the SDT's response to your comments in question #1.**		
Colorado Springs Utilities	No	In order to avoid burdensome paperwork of traditional fault study values and existing

Organization	Yes or No	Question 4 Comment
		fault study values, common thresholds should be determined for initiating a review. Common thresholds can be common device ratings, or agreed upon levels at interconnects. As in Facility ratings, each owner should have device ratings for device capacities and can include short circuit ratings, which if exceeded can initiate a review.
Response: Thank you for your comment. **The drafting team agrees with your comment about establishing a common threshold but it is related to Protection System coordination rather than device ratings. The threshold we arrived at is a 10 % deviation of the Fault current values used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1.**		
Tennessee Valley Authority	No	1. The 10% change is too narrow for protection system studies. Accuracies of PT, CT, wiring, and modeling all add together and therefore the threshold for a new protection system study should be 15%.a) 2. In R2, Part 2.2, replace the term “deviation” with “change.” (Note: For this calculation all that’s required is to calculate percent change. i.e. Webster’s dictionary definition of “deviation” is 1) A variation that deviates from the standard or norm; "the deviation from the mean”. 2. The difference between an observed value and the expected value of a variable or function.) 3. In R2, Part 2.2, replace the term “present” with “new” and the term “most recent” with “previous”. Also reflect this terminology change in the % Change equation.(the use of the terms “present” and “most recent” can be perceived to be the same.) 4. It is also recommended that “V” for value be replaced by “I” for current. d) In R2, Part 2.1, please add “new”, delete “present” and add either “under normal conditions” or “maximum system conditions” so that it states “Perform a new short circuit study to determine the fault current values under normal conditions, not less than once every 24 months."

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. 1. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.** 2. **The drafting team believes that the term "deviation" is properly used in R2 Part 2.2 and is synonymous with the term "change".** 3. **The drafting team believes that the terms "present" and "new" are properly used in R2 Part 2.2 and are synonymous with your recommended changes.** 4. **Per your suggestions and others, the drafting team has modified the equation to replace "V" with "I". The drafting team modified Requirement 2.1 to read "Perform a short-circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus, not less than once every 24 months."**		
ACES Power Marketing Standards Collaborators	No	(1) While we do not have an issue with the +/- 10% Fault current threshold, we question if the TO should be responsible for calculating the percent deviation for all Protection Systems for all Interconnected Facilities. Rather the TO should be responsible for calculating Fault currents on its transmission system and should be required to calculate the percent deviation for only those breakers and associated Protection Systems it owns and are protecting an Interconnected Facility and that it has performed the Protection System Study (PSS). The TO should communicate the Fault current to the owners of other Protection Systems protecting the Interconnected Facilities for them to calculate the percent deviation. (2) The main part of the requirement needs to be modified to further clarify for which Interconnected Facilities the TO is conducting short studies. As it is written now, each TO has to perform these short circuit studies for each Interconnected Facility. This literally means a TO has to perform short circuit studies for Interconnected Facilities for which it has no information or is even remotely responsible. For example, a literal reading would mean a TO in the Eastern Interconnection would have to perform a short circuit study for an Interconnected

Organization	Yes or No	Question 4 Comment
		Facility in the Western Interconnection. Obviously, this is not the drafting team's intention but the language does need refinement.

Response: Thank you for your comments.

1. **The drafting team changed the text in Requirement R2 to read: "For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall".**
2. **The drafting team changed the text in Requirement R2 to read: "For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall".**

Organization	Yes or No	Question 4 Comment
Kansas City Power & Light	No	a. Primary protection of most transmission lines is impedance based. Sensitive ground over current systems are used for communications assisted tripping and time ground over current systems are typically used as backup protection. Some line protection is differential based. Some entities also apply instantaneous ground over current relaying for faults at some fraction of the protected line. Increases in fault current do not affect impedance based relaying. Communications assisted sensitive ground elements are set well below available fault current levels and increases in fault current levels will not hinder proper operation. Differential based systems would also not be harmed by fault current increases unless fault currents increase enough to result in ct saturation. Since time ground over current relays are usually used as backup protection they are typically set only to operate if the primary relaying protection has failed. These relays are typically set to coordinate based on time delays for ground faults on the protected line. Because the overcurrent curves are based on a log scale the increase in current magnitude does not correlate to the same percentage in time. Instantaneous ground over current elements are most susceptible to misoperations caused by increases in fault current, however these elements should be initially set to protect only the first 50 to 70% of the protected line based on the fault current at the remote end. With this in mind a fault current increase of 10% is not significant by itself to require

Organization	Yes or No	Question 4 Comment
		a setting review and it is very difficult to see how a 10% decrease can affect the coordination unless over current elements are the primary protection elements or over currents elements can prevent the operation of the other protection functions. If the SDT is adamant about having a periodic review of fault current levels then the time should be extended to 5 years b. and the fault current level should be increased to 20% on the protected line.
Response: Thank you for your comments. a. **Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation. The drafting team believes studies associated with changes that would affect the coordination in less time would be triggered by other requirements in this standard.** b. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.**		
Operational Compliance	No	1. We agree with the 10% value, but not with the actual wording in the Standard. The Standard reads "2.3 Where the calculation performed....indicates a deviation in Fault current of 10% or greater". It is not clear whether this means 10% Fault current deviation above or below, both or just above. 2. We also suggest that specific defined trigger events prompt a Fault current review for affected Interconnection Facilities, instead of fault current reviews being required every 24 months for every Interconnection Facility.
Response: Thank you for your comments. 1. **The drafting team changed the formula to take the absolute value of the calculated percent deviation to make it clear that the**		

Organization	Yes or No	Question 4 Comment
percent change is plus or minus 10 %. **2. Requirement 3 provides the specific defined trigger events as you suggest, however, the drafting team believes that a periodic Fault current study is still necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination.**		
Pacific Gas and Electric Company	No	The requirement to run the fault study to determine if there is any 10% change is only required once every 24 months per requirement R2.1. But if you run a batch study and find a bunch of 10% changes, you only have 6 months to do all the coordination studies. We think a 12 month window for performing the coordination studies is more appropriate.
Response: Thank you for your comment. **The drafting team believes that complying with Requirement R3 will minimize the situation you describe.**		
Western Area Power Administration	No	We have concerns over what NERC considers to be a "Protection System Study". Needs to be defined more clearly.
Response: Thank you for your comment. **The drafting team modified the description of the term "Protection System Study" in the Technical Guidelines section of the standard.**		
Independent Electricity System Operator	No	We do not agree or disagree with the 10% deviation threshold. In the Technical Justification document, the SDT indicates that "The SDT investigated various inputs that would trigger a review of the existing Protection System Studies, and determined through the experience of the SDT members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated Protection System Study may be necessary." Lacking statistical or detailed studied results, this basis is as good as any. However, there does not appear to be any assessment made on the potential

Organization	Yes or No	Question 4 Comment
		BES reliability risks when the Fault current deviates by less than 10%. Many Protection Systems' settings are linked to Fault current level and as such, deviation as low as a few percent may render a Protection relay not operating as intended. We suggest the STD to assess the risk of not conducting a verification study for the Protection Systems when Fault current deviates from past values at a lower range to either confirm that a 10% deviation would be a safe trigger, or revise it according to the findings of the risk assessment. (NTD: we may also suggest that a Protection System Study should be required for every BES modification that is in the electrical proximity of the Interconnected Facility and is expected to modify the Fault current levels.)
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Entities are not precluded from notifying other entities at levels of Fault currents lower than 10 %. The drafting team did not make any of the suggested changes. Further, Requirement 3 should capture Fault current changes caused by BES additions.**		
Sacramento Municipal Utility District	No	1. We do not agree with this requirement. The selection of a +/- 10% threshold is entirely arbitrary. For instance, some entities will set Z1 to 80%, leaving a 20% margin for error. Some entities will set it at 90%. The SDT should allow entities to decide for themselves when a review is needed. 2. As we stated before, the results based objective is to communicate and coordinate. Not to prove whether the fault current at a certain bus is +/- XX% greater than it was at some time in the past. Furthermore, the SDT itself states there is no proof that failure to coordinate protection systems is causing reliability issues. If entities allow their systems to become uncoordinated, we would expect it to come to light as a Misoperation and be handled under PRC-004. We do not agree it is the TO's responsibility to maintain a short circuit model for other entities. What responsibility does the TO take on if it models a generator's short

Organization	Yes or No	Question 4 Comment
		circuit capability incorrectly? This is a very real concern among transmission protection engineers when attempting to model large wind farms with their proprietary models.
Response: Thank you for your comments. 1. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Entities are not precluded from notifying other entities at levels of Fault currents lower than 10%.** 2. **The expectation is that the Transmission Owner will be reviewing short circuit values on the Transmission Owner's facilities only. When the Transmission Owner identifies a 10% deviation at a location where there are Interconnected Elements, the Transmission Owner would notify the other entity(s). The Transmission Owner is identified as the entity responsible for performing the Fault current studies because they maintain the data necessary to perform the studies.**		
ReliabilityFirst	No	It may be appropriate to trigger a coordination review based on multiple criteria. For instance, perhaps coordination should be verified at the interconnection at least once every 7 years, as well as whenever the available fault current at the point of interconnection changes by more than 10%. There may be other better indicators when coordination should be checked as well such as a percentage change in system impedances at the interconnecting buses. RFC also questions whether there is a justification for choosing the 10% criteria (rather than say 5%)
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Further, Requirement 3 should capture Fault current changes caused by BES additions; therefore, the drafting team believes a periodic study as you suggest is not warranted.**		
Idaho Power Company	No	No, We are unsure whether a 10% trigger level is appropriate in this context as the location of the fault is not specified in this Requirement. Faults used to properly set a

Organization	Yes or No	Question 4 Comment
		protective relay will be made at multiple locations and with various source conditions. The Requirement should be more specific in order to achieve consistent coordination among entities.
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The 10% trigger will potentially initiate a Protection System Study which could involve evaluating Faults at multiple locations and with various source conditions.**		
LCRA Transmission Services Corporation	No	1. A 10% change in fault current is not an appropriate criterion or "trigger" for relay coordination review. It does not meet the standard's purpose to ensure speed and selectivity requirements associated with protection system coordination. Requirement R2 should read as follows: "For each Interconnected Facility, each Transmission Owner that has ownership of the protective relay portion of the Protection System shall: " 2. Requirement R2.2:LCRA TSC recommends not including this requirement. Requirement R2.3: Should the SDT decide to include requirement R2.2, then rephrase R2.3 as follows:"Where the calculation performed, pursuant to Requirement R2, Part 2.2, indicates a deviation in Fault current of 10% or greater, notify each non-transmission owner of the Interconnected Facility, at which the 10% or greater deviation applies, within 30 calendar days after identification. As an alternative requirement to R2.2 and R2.3, LCRA TSC recommends the following language to R2.1, 2.2 and 2.3:2.1. Perform a short circuit study to determine the present Fault current values, not less than annually. 2.2. Pursuant to Requirement R2, Part 2.1, provide summary results to each directly impacted non-Transmission Owner entity at the Interconnected Facility, within 30 calendar days after completion of the short circuit study. 2.3 Delete

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. 1. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin.** 2. **The drafting team believes the requirement is appropriate as written.**		
Exelon	No	1. Exelon requests that the conditions under which the required short circuit (SC) study are to be performed should be defined. What future reinforcements should be assumed in the SC model, since the result will depend on these assumptions? 2. In R2, 10% or greater deviation in Fault Current may not be adequate to perform Short Circuit (SC) Study. It should be clearly stated what threshold is adequate to perform SC study successfully, and 3. the SDT should provide some examples how the 'six-month" time frame is considered a "reasonable amount "of time to perform the SC study.
Response: Thank you for your comments. 1. **The drafting team revised Requirement R2, Part 2.1 to indicate that the maximum available Fault current values are to be calculated. It is intended that current system models are to be used when performing the 24 month calculations, not future models.** 2. **The drafting team maintains that the 10% threshold is adequately sensitive and should be conducted every twenty-four months.** 3. **The drafting team believes that 6 months is adequate time to perform a Protection System Study triggered by a 10% deviation in current magnitudes at an interconnection. These Protection Systems should have been previously checked and documented under a Protection System Study and any settings changes should be minor.**		
Massachusetts Municipal Wholesale Electric Company	No	MMWEC endorses the comments submitted by NPCC.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. **See the response provided to NPCC's comments.**		
Public Service Enterprise Group	No	We disagree with this requirement for several reasons. a. A change in short circuit Fault current, in many cases, does not require relays to be reset. The requirement to perform a Protection System Study for this reason alone will likely provide no benefit when the relay performance is not dependent on short circuit current level. If the relay performance is directly dependent on short circuit level, then a % change in short circuit level may be appropriate. This distinction should be spelled out in R2. b. It is common for relays to be set at 30-50% of the Fault current or 150%-200% of the full load current. A change of +/- 10% in Fault current would have little to no impact on the existing settings and coordination.
Response: Thank you for your comments. **a. Requirement R1, Part 1.1.2 allows you to offer a justification as to why a Protection System Study is not needed even if Fault duty increases by 10%.** **b. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin.**		
Public Utility District No. 1 of Snohomish County	No	Comments: 1) SNPD does not agree with this requirement. The selection of a +/- 10% threshold is entirely arbitrary. For instance, some entities will set Z1 to 80%, leaving a 20% margin for error. Some entities will set it at 90%. The SDT should allow entities to decide for themselves when a review is needed. 2) As we stated before, the results based objective is to communicate and

Organization	Yes or No	Question 4 Comment
		coordinate. Not to prove whether the fault current at a certain bus is +/- XX% greater than it was at some time in the past. Furthermore, the SDT itself states there is no proof that failure to coordinate protection systems is causing reliability issues. If entities allow their systems to become uncoordinated, we would expect it to come to light as a Misoperation and be handled under PRC-004. We do not agree it is the TO's responsibility to maintain a short circuit model for other entities. What responsibility does the TO take on if it models a generator's short circuit capability incorrectly? This is a very real concern among transmission protection engineers when attempting to model large wind farms with their proprietary models.
Response: Thank you for your comments. 1. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Entities are not precluded from notifying other entities at levels of Fault currents lower than 10%.** 2. **The expectation is that the Transmission Owner will be reviewing short circuit values on the Transmission Owner's facilities only. When the Transmission Owner identifies a 10% deviation at a location where there are Interconnected Elements, the Transmission Owner would notify the other entity(s). The Transmission Owner is identified as the entity responsible for performing the Fault current studies because they maintain the data necessary to perform the studies.**		
Georgia Transmission Corporation	No	1) Using "V" to denote fault current values may help the non-engineer reading the document, but "I" is the common nomenclature for current in the utility industry. The equation in R2.2 should use "I" in place of "V". 2) There is a risk in using calculated fault currents of the most recent PSS and not existing relay settings. If the entity uses 10% margin in settings it will be too late to make settings changes. Should the margin be based on existing fault calculations and existing relay settings basis?
Response: Thank you for your comments.		

Organization	Yes or No	Question 4 Comment
1. The drafting team made the suggested change replacing "V" with "I" in the equation. 2. The drafting team does not understand the scenario you describe.		
Platte River Power Authority	No	The selection of a +/- 10% change in an Interconnected Facilty's Fault current value is arbitrary. The results based objective is to communicate and coordinate.
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin.**		
MWDSC	No	1. Every TO should not be required to perform a short-circuit study every 24 months if there were no significant changes to that TO's BES facilities. Changes in adjoining interconnected BES systems could change short-circuit duties for an adjoining TO's system. The TO whose BES changes should be responsible for performing short-circuit duties on all adjoining systems as part of Requirement R3. 2. In addition, FAC-002-1 requires TOs to coordinate with TPs and PAs in the assessments of proposed new facilities, including evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission through steady-state, short-circuit, and dynamics studies.
Response: Thank you for your comments. **1. The drafting team believes that a periodic Fault current study is necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes. Further, Requirement 3 should capture Fault current changes caused by BES additions.** **2. The statements you make about FAC-002-1 are correct, however, Requirement R1.4 of that standard requires the**		

Organization	Yes or No	Question 4 Comment
Transmission Owner to evaluate system performance under short circuit and other conditions in accordance with the TPL-001-0, TPL-002-0 and TPL-003-0 planning standards. The "coordination" reference in FAC-002-1 is synonymous with "cooperation". No reference to Short Circuit Studies for the purpose of verifying protective relay coordination is made in FAC-002-1. The drafting team believes that Short Circuit Studies as proposed in PRC-027 adequately accomplish the purpose of the standard.		
NPPD	No	Monitoring for a 10% change in faults could trigger studies that are not needed and it is not necessarily a good indicator settings updates are needed. It would be more practical to require a review of settings on a set interval (5 years) or as required by R3.
Response: Thank you for your comments. **The drafting team believes that a periodic Fault current study is necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin.**		
NextEra Energy Inc	No	It would seem that NERC Standards efforts, such as PRC-027 should focus on areas that have a record of poor performance and a contributor to misoperations. The area of tie line protection addressed in PRC-027 is not an area of poor performance, see page 4 of the attachment "....Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations". Areas that are less problematic should be addressed by NERC with less intrusive methods such as Industry Alerts, general cautionary statements or a standard with less detailed documentation requirements. Thus, PRC-027, as drafted, will unnecessarily require additional focus and resources be placed in an area that has not been a problem for the reliability of the BES. Alternatively, PRC-027 should be drafted much less prescriptively from a technical standpoint, and allow for more discretion on how to conduct the study and how to coordinate the results. The prescriptive nature of many of the technical

Organization	Yes or No	Question 4 Comment
		requirements PRC-027 is so narrow that it may counterproductive. A results-based approach here should focus more on conduct a study and coordinating the results, rather than dictating how the technical requirements of how study is to be completed.
Response: Thank you for your comments. **PRC-027-1 is replacing Requirements R2 and R3 of PRC-001-2. The drafting team is developing a standard based on a SAR accepted by the Standards Committee and is addressing directives issued by FERC in Order 693.**		
ExxonMobil Research & Engineering	No	
Liberty Electric Power LLC	No	
National Grid USA / Niagara Mohawk	Yes	Please clarify where the fault is to be placed and where the deviation is to be observed. One possibility is to place the fault at a bus at one end of the tie and then determine the deviation in the current in each element connected to said bus.
Response: Thank you for your comment. **Per your suggestions and others, the drafting team has modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
SERC Protection and Control Subcommittee	Yes	a) In R2 2.2, replace the term "deviation" with "change." (Note: For this calculation, all that is required is to calculate percent change. For example, Webster's dictionary definition of "deviation" is: 1) a variation that deviates from the standard or norm; "the deviation from the mean" 2) the difference between an observed value and the expected value of a variable or function.) b) In R2 2.2, replace the term "present" with "new" and the term "most recent" with

Organization	Yes or No	Question 4 Comment
		"previous". Also reflect this terminology change in the %Change equation. (The use of the terms "present" and "most recent" can be perceived to be the same.) c) It is also recommended that "V" for value be replaced by "I" for current. d) In R2 2.1, please add "new", delete "present" and add either "under normal conditions" or "maximum system conditions" so that it states "Perform a new short circuit study to determine the Fault current values under normal conditions, not less than once every 24 months.
Response: Thank you for your comments. **a. The drafting team believes that the term "deviation" is properly used in R2 Part 2.2 and is synonymous with the term "change".** **b. The drafting team believes that the terms "present" and "new" are properly used in R2 Part 2.2 and are synonymous with your recommended changes.** **c. Per your suggestion, the drafting team has modified the equation to replace "V" with "I".** **d. The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
Associated Electric Cooperative, Inc., JRO00088	Yes	1. A 10% threshold seems simple, but the SDT may or may not wish to clarify the formula to be applied because any of the following is a valid interpretation: 1) abs(Vscs - Vpss)/Vscs, 2) abs(Vscs - Vpss)/Vpss, 3) abs(Vscs - Vpss)/0.5(Vscs + Vpss), 4) abs(Vscs -Vpss)/Max(Vscs,Vpss), or 5) abs(Vscs-Vpss)/Min(Vscs,Vpss). 2. Also see SERC PCS Comments.
Response: Thank you for your comments. **1. Initially, the posted standard was missing the equation but the document was reposted with the equation included. The drafting team modified the equation to include the absolute value.**		

Organization	Yes or No	Question 4 Comment
2. Please see the drafting team's responses to the SERC PCS comments.		
Southern Company	Yes	When calculating the "+/- 10 % Fault current threshold", the use of bus fault values vs the line contribution values should be clarified.
Response: Thank you for your comment. **The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
Texas Reliability Entity	Yes	1. Using a +/- 10% change is a good threshold, with the understanding that if a change in fault current value of less than 10% results in a need to change relay settings, then Requirement R3.1 will cover the coordination between entities in that case. 2. Additional comment: For R2.1, Does the SDT also want to consider other system studies in addition to short circuit studies (e.g. critical clearing time studies at generation facilities needed for breaker failure coordination, equipment rating studies, or stability studies)?
Response: Thank you for your comments. **1. Your understanding about R3.1 covering the scenario you describe is correct.** **2. The drafting team doesn't believe that the other studies you mention should be considered in this standard.**		
Xcel Energy	Yes	Similar comments on measure M5 as contained in item 3 above on measure M2.This provision should become effective 36 months after the effective date of the standard.
Response: Thank you for your comments. **The drafting team believes that the description of the evidence in the Measure is acceptable. The drafting team further believes**		

Organization	Yes or No	Question 4 Comment
that the 24 month time frame to perform a short circuit study is adequate.		
Ameren	Yes	(1) In R2 2.1 we request the SDT add “under normal conditions” or “under maximum system conditions” so that it states “Perform a short circuit study to determine the present Fault current values under normal conditions, not less than once every 24 months. “ (2) We request the SDT clarify which Interconnection Facility fault current values are to be compared. If the intent is to keep this general so the entities have the flexibility to compare those fault current values that the entities judge appropriate, please state. Otherwise we suggest adding “Specifically find fault current values flowing into each terminal of the Interconnected Facility for independently applied single line to ground and 3-phase short circuits at its other terminal(s).” (3) We request the SDT change R2 2.2 wording to “Calculate the percent [delete - deviation] change between the Fault current values (single line to ground and 3-phase [delete - for the bus(s) or Element(s)] flowing into each terminal of the Interconnected Facility under consideration) used in the most recent Protection System Study...”. This along with our recommended change to R2 2.1 clarifies the short circuit values that are to be compared. (4) We request the SDT change R2 2.1 to “not less than once every 5 years” for consistency with TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. Our experience is that PRC-027-1 R3 will trigger almost all Protection System Studies anyhow.

Response: Thank you for your comments.

1. **The drafting team modified Requirement 2.1 to read “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1.”**
2. **The drafting team modified Requirement 2.1 to read “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus**

Organization	Yes or No	Question 4 Comment
where a Protection System Study is available per Requirement R1.” **3. The drafting team believes that the term “deviation” is properly used in R2 2.2 and is synonymous with the term “change”. We also believe that the changes made to R2.1 clarify where the fault is to be applied and monitored.** **4. The reliability intent and purpose of the two standards is different. The drafting team agrees with you that Requirement R3 should capture Fault current changes caused by other BES additions.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	Yes	Ingleside Cogeneration LP agrees that a 10% delta in Fault current is material and would warrant further study. However, we are not sure how these studies would correlate to those managed by Planning Coordinators and Transmission Planners. It seems like these entities would have to be involved in any studies that may result in a change in relay settings or a Protection System upgrade.
Response: Thank you for your comment. **The drafting team does not believe the Planning Coordinators or Transmission Planners need to be involved in Protection System Studies associated with verifying protective relay coordination.**		
American Transmission Company	Yes	ATC does agree with the premise of the a 10% change but believes that the SDT needs to provide a clear definition of which fault current must change 10% to trigger the notification requirements and initiation of a protection study. Fault current on an interconnecting line may change very little even though bus fault contributions from other lines may have increased considerably, affecting in feed current and relay settings.
Response: Thank you for your comment. **The drafting team modified Requirement 2.1 to read “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1.”**		

Organization	Yes or No	Question 4 Comment
Duke Energy	Yes	However it's unclear what Fault duty is being referred to. Is it the total Fault current at the bus, or Fault current that flows down the line or to the generator? It should also be clarified that Fault duty is the normal case (i.e. with all sources and all lines in-service).
Response: Thank you for your comment. **The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
Oncor Electric Delivery Company LLC	Yes	Oncor takes the position that the 10% fault current threshold criteria is the only criteria needed;
Response: Thank you for your comment.		
Dominion	Yes	a) In R2-2.2 Replace the term "deviation" with "change". {(Note: For this calculation all that is required is to calculate percent change. i.e. Webster's dictionary definition of "deviation" is 1) A variation that deviates from the standard or norm; "the deviation from the mean". 2. The difference between an observed value and the expected value of a variable or function. This is not a statistical calculation.) } b) In R2-2.2, Replace the term "present" with "new" and the term "most recent" with "previous". c) Change the % Deviation Equation to % Change. Reflect as stated above in the equation legend (the use of the terms "present" and "most recent" can be perceived to be the same). d) Replace "V" (Value) with "I" (Current) in the % Change Equation. "V" is frequently used to represent Voltage and this could lead to confusion. e) In M5 Replace the term "deviation" with "change".

Organization	Yes or No	Question 4 Comment
		f) In R2-2.1 please add “new”, delete “present” and add either “under normal conditions” or “maximum system conditions” so that it states “Perform a new short circuit study to determine the Fault current values under normal conditions, not less than once every 24 months.
Response: Thank you for your comments. a. **The drafting team believes that the term “deviation” is properly used in R2 Part 2.2 and is synonymous with the term “change”.** b. **The drafting team believes that the terms “present” and “new” are properly used in R2 Part 2.2 and are synonymous with your recommended changes.** c. **See response to “a”.** d. **Per your suggestions and others, the drafting team has modified the equation to replace “V” with “I”.** e. **See response to “a”.** f. **The drafting team modified Requirement 2.1 to read “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1.”**		
Southwest Power Pool NERC Reliability Standards Development Team	Yes	
Luminant	Yes	
Imperial Irrigation District (IID)	Yes	
FirstEnergy	Yes	
Santee Cooper	Yes	

Organization	Yes or No	Question 4 Comment
Western Small Entity Comment Group	Yes	
ISO RTO Council SRC	Yes	
Progress Energy	Yes	
Salt River Project	Yes	
American Electric Power	Yes	
Flathead Electric Cooperative, Inc.	Yes	
City of Austin dba Austin Energy	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Tri-State G & T	Yes	
Wisconsin Electric Power Company	Yes	
NV Energy	Yes	
Dairyland Power Cooperative	Yes	
Portland General Electric	Yes	

Organization	Yes or No	Question 4 Comment
Company		
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
Trans Bay Cable	Yes	
CenterPoint Energy	Yes	
Clark Public Utilities	Yes	
South Carolina Electric and Gas	Yes	
MRO NSRF		1. The NSRF recommends that a clear definition of what fault current must change 10 % to trigger the notification requirements and initiation of a protection study. Fault current on an interconnecting line may change very little even though bus fault contributions from other lines may have increased considerably, affecting in-feed current and relay settings. 2. It would be easier to implement a time-based periodic review of settings every 5 - 8 years (or sooner if required by conditions in Requirement R3). 3. R2 is redundant and could subject entities to double jeopardy in conjunction with the new TPL standards which will require annual short circuit studies and NERC studies should not be duplicated to avoid double jeopardy. 4. At a minimum, the 24 month requirement should be changed to at least every 2 calendar years. This would align with the annual requirement for the TPL standards. The new TPL standards are in limbo with FERC's rejection to footnote b.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. **1. The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."** **2. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Entities are not precluded from notifying other entities at levels of Fault currents lower than 10%. The drafting team did not make any of the suggested changes. Further, Requirement 3 should capture Fault current changes caused by BES additions.** **3. The requirements in the two standards are different and therefore not redundant.** **4. The drafting team disagrees and believes that the 24 month frequency is adequate.**		
El Paso Electric Company		It is unclear whether the proposed standard intends to reach 10% or greater deviations that accumulate over the course of a more extended period of time (i.e., greater than 2 years), or whether an entity can seek to perform multiple studies within a compressed period of time in such a way that it can ensure that a 10% deviation will not be reached from study to study, as illustrated below: o Study performed in Year 1 shows a 5% deviation o Study performed 12 months later (in Year 2) shows a 5% deviation o Study performed 12 months later (in Year 3) shows a 5% deviation[Cumulative deviation of 15% within 3 years, but only a 5% deviation from study to study]
Response: Thank you for your comment. **The intent is to capture cumulative changes over time and perform a new Protection System Study when the 10% threshold is reached. The starting point is the most recent Protection System Study in which the relay settings were established or verified. At least every two years after that, a new Short Circuit Study is performed and the new short circuit values are compared to the short circuit values from the original Protection System Study. In your example, a new Protection System Study would be triggered after**		

Organization	Yes or No	Question 4 Comment
the Short Circuit Study in year 2 when the cumulative 10% deviation occurred.		
El Paso Electric		It is unclear whether the proposed standard intends to reach 10% or greater deviations that accumulate over the course of a more extended period of time (i.e., greater than 2 years), or whether an entity can seek to perform multiple studies within a compressed period of time in such a way that it can ensure that a 10% deviation will not be reached from study to study, as illustrated below: o Study performed in Year 1 shows a 5% deviation o Study performed 12 months later (in Year 2) shows a 5% deviation o Study performed 12 months later (in Year 3) shows a 5% deviation[Cumulative deviation of 15% within 3 years, but only a 5% deviation from study to study]
Response: Thank you for your comment. **The intent is to capture cumulative changes over time and perform a new Protection System Study when the 10% threshold is reached. The starting point is the most recent Protection System Study in which the relay settings were established or verified. At least every two years after that, a new Short Circuit Study is performed and the new short circuit values are compared to the short circuit values from the original Protection System Study. In your example, a new Protection System Study would be triggered after the Short Circuit Study in year 2 when the cumulative 10% deviation occurred.**		
mason		No comment

5. **In Requirement R3, the SDT included a list of proposed changes that impact the coordination of Protection Systems and would initiate a need to inform other entities. Do you agree that this is an appropriate and inclusive list? If not, please provide specific suggestions for additions or deletions with your reasoning(s) in the comment area.**

Summary Consideration:

Several commenters suggested minor wording changes to the list included in Requirement R3, Part 3.1. The drafting team considered all of the suggestions and made changes including combining the second and third bullets to read as follows 'Changes to a transmission system Element that change any sequence or mutual coupling impedance'. Also, the fourth and fifth bullets were modified to indicate that impedance changes are what need to be communicated.

A few commenters had concerns with the 30 day time frame in Parts 3.2 and 3.3 while other commenters wanted them eliminated. The drafting team explained that they believed the 30-day time frame is appropriate and declined to make the change, and further explained the purposes for the Parts and retained them with minor wording changes.

Some commenters wanted to remove reference to schedules in the requirements. The drafting team reinforced that they believe the sharing of project schedules is a necessary communication between entities.

Some commenters did not like the use of the word "error" in Requirement 3, it was restated as follows: Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.

A few commenters expressed concerns that there is redundancy between this draft standard and several FAC standards. The drafting team stated their belief that these concerns were not applicable.

Organization	Yes or No	Question 5 Comment
Southwest Power Pool NERC Reliability Standards Development Team	No	In R3 we would suggest that re-rating could be use as a temporary procedure which is addressed in the TOP standards and if the drafting team needs to include these types of re-ratings that they be more specific to exclude the temporary re-ratings. Changes to generator unit(s), including replacements, Output change that causes a change in the protection system, and impedances

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment **The drafting team believes that if a temporary or permanent re-rating modifies the conditions used in the coordination of Protection Systems of the Interconnected Stations, then any associated protective relay setting changes must be provided to the other entities.**		
Pepco Holdings Inc. & Affiliates	No	The 10% threshold would be acceptable providing the following changes were made to Requirements R2.1 and R2.2:R2.1 – 1. Re-word Requirement R2.1 to read: "Perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities, not less than once every 24 months. 2. R2.2 - Re-word Requirement R2.2 to read: "Calculate the percent deviation between the maximum available Fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation..."The existing wording requires one to "calculate the percent deviation between the fault current values ... for the bus(s) or Elements(s) under consideration". 3. Including the phrase "or Element(s) under consideration" increases the complexity of the periodic fault screening requirement significantly. Instead of performing a relatively easy bus fault summary routine (available in most batch short circuit programs) individual branch current in various coordination pairs must be examined. Take for example the system shown in Figure 1 in the Application Guidelines. Instead of just screening the available bus fault current at the point of interconnection (the ownership boundary between the two entities), fault current in each "element under consideration" used in the Protection study must be calculated. This would mean determining fault current flows through breakers A, B, C, D, E, F, G, & H) under various fault scenarios and

Organization	Yes or No	Question 5 Comment
		comparing them to those used in the previous coordination study. This is far from a simple task and not conducive to a "batch" screening tool. The intended purpose of R2.2 is to catch external system changes that have over time led to gradual increases in fault current that may require the Protection System Study to be re-examined. A simple year to year bus fault comparison would serve this purpose. System changes at, or immediately adjacent to, the interconnection point, which could lead to a re-distribution of fault currents through the effected element(s), would be caught elsewhere under R3.1 "Additions, removals, or replacements of transmission Elements".
Response: Thank you for your comments. **1. Per your suggestions and others, the drafting team has modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."** **2. The drafting team believes the existing wording was sufficient and did not make your suggested change.** **3. The drafting team did remove the word "or Element(s)" as you suggested.**		
Hydro One	No	While we agree with the principle of exchanging information, R3.1 is confusing "...or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities." We believe that this statement is too inclusive. It implies that changes in facilities other than the Interconnected Facility need to be communicated and is too open for interpretation. Suggest the scope be better defined and limited only to changes at the Interconnected Facility.
Response: Thank you for your comment **The drafting team revised the term "Interconnected Facilities" to "Interconnected Element". The drafting team believes changes at other Facilities that modify the conditions used in the coordination of Protection Systems of the Interconnected Elements need to be communicated because they could lead to coordination issues. An example of this is a new substation installed near**		

Organization	Yes or No	Question 5 Comment
Interconnected Elements that could require a change in impedance relay settings for overreaching zones.		
Luminant	No	Luminant agrees with R3.1 and 3.2. Luminant suggests that the language in this requirement be revised so it is clear what is to be provided between the parties.
Response: Thank you for your comment. **Requirement R3, Parts 3.1, 3.2, and 3.3 each refer back to the main Requirement R3. The drafting team revised Requirement R3, Part 3.2 to clarify that it pertains to responses for Protection System coordination information.**		
Bonneville Power Administration	No	BPA believes that it is not practical to list all of the possible changes that could impact the coordination of protection systems. Any such list will likely lead to unnecessary notification in most cases, while failing to recognize unusual situations that could cause miscoordination. BPA is in favor of a simplified approach where notification is provided to the owner of the remote terminal(s) whenever a change is made to the protection scheme at one terminal.
Response: Thank you for your comment. **The drafting team appreciates your concern but believes changes to a protection scheme are not the only system changes than can lead to miscoordination.**		
FirstEnergy	No	Requirement 3, Part 3.1 - We believe that some entities registered as both a TO and a GO may face Standards of Conduct issues if a TO is required to provided the “bulleted” data specified within the Part 3.1.
Response: Thank you for your comment. **The drafting team does not believe that the requested exchange of information would violate the Standards of Conduct for an entity registered as both a GO and a TO.**		
Santee Cooper	No	In R3, 3.3.1, change the wording to address “changes” instead of “corrections” for “errors.” Many changes are made that are not the result of errors. The purpose here

Organization	Yes or No	Question 5 Comment
		should be to communicate changes, and people shouldn't have to debate whether or not to make an "improvement" (not because of an error or misoperation) because it may be construed as a correction of an error.
Response: Thank you for your comment **Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Western Small Entity Comment Group	No	R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward.
Response: Thank you for your comment. **Requirement R2 requires the Transmission Owners to perform the Fault current studies because they have the necessary information to perform the studies. Requirement R1 requires all applicable entities to perform Protection System Studies. Requirement R3 requires all applicable entities to exchange the information necessary for Protection System coordination.**		
Northeast Power Coordinating Council	No	DP must be excluded from R3. See the response to Question 2.
Response: Thank you for your comment **The drafting team believes that the Owner of the Protection System is responsible for sharing information to ensure its Protection Systems are coordinated with others.**		
PPL Corporation NERC Registered Affiliates	No	See comment in question #1 above.
Response: Thank you for your comment.		

Organization	Yes or No	Question 5 Comment
The drafting team revised the term "Interconnected Facilities" to "Interconnected Element". The drafting team believes that coordination is required at all Interconnected Elements between Transmission Owners and Generator Owners regardless of whether the entity is an independent Generator Owner. It is acknowledged that in many cases, the majority of the work associated with this task will fall on the Transmission Owner; however, the coordination of some Protection Systems applied on generators must be verified by the Generator Owner.		
SERC Protection and Control Subcommittee	No	a) Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout this standard already address notification requirements. b) In R3 3.3.1, change requirement to read: "Changes are made to a Protection System as a result of findings during misoperation investigations, commissioning, or maintenance activities."(The current wording implies that all findings are due to errors. The reference to errors should be removed and the emphasis of this requirement needs to be placed on "changes" made to Protection Systems when it becomes apparent that a change is required which impacts coordination of relays.)
Response: Thank you for your comment. **a. The drafting team believes it is necessary to share the pertinent scheduling information that could affect the other party.** **b. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Colorado Springs Utilities	No	Specific project schedules can potentially cause violation of other requirements. 1. A proposed change of conductor spacing, which can be interpreted as a change of one transmission structure requires notification to other entities, which we feel is excessive. 2. Re-rating of generators rarely changes the protection, impedances or coordination involved. It is common to re-rate units depending on external factors to the

Organization	Yes or No	Question 5 Comment
		generator which also provides excessive reviews and project schedule notifications. 3. This section also implies notifications must be made after like and kind replacements of equipment found during misoperation investigations, but not those found during testing. On larger systems this requirement would be difficult unless notifications were made more than twice a month, which would require a large tracking system of who, what, and when information is sent to interconnected utilities.
Response: Thank you for your comment **1. The drafting team has modified the bullet in 3.1 to read "Changes to a transmission system Element that changes any sequence or mutual coupling impedance'; therefore, the noted change in spacing that does not change the impendence used in the system model would not need to be communicated.** **2. The drafting team believes that, regardless of the probability of a change affecting Protection Systems; it must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.** **3. The drafting team believes that testing is included in commissioning and maintenance activities. The drafting team believes that relay replacement information needs to be provided to the interconnecting entity and that 30 calendar days is sufficient and adequate to provide the notice.**		
Tennessee Valley Authority	No	a) Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout this standard already address notification requirements. b) In R3,Part 3.3.1, change Requirement to read: "Changes are made to a Protection System as a result of findings during Misoperation investigations, commissioning, or maintenance activities." (The current wording implies that all findings are due to errors. The reference to errors should be removed and the emphasis of this Requirement needs to be placed on "changes" made to Protection Systems when it becomes apparent that a change is required which impacts coordination of relays.)

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. a. **The drafting team believes it is necessary to share the pertinent scheduling information that could affect the other party.** b. **Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Associated Electric Cooperative, Inc., JRO00088	No	1. AECI believes the industry would be better served by placing this list of items into a Guidance document, and rephrasing R3 to include only "field-changes known to modify the conditions used in coordination settings of Protection Systems." Although some of the listed items are direct-impact, as currently drafted, any field-equipment changes are potentially in scope, regardless of proximity to the Interconnected Facility(s) of interest. 2. With exception of R3.1 Bullet #1, the R2.3 10% is a better metric and the other Guidance bullets and wording we proposed above, should be added into R2.3.
Response: Thank you for your comment 1. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** 2. **The drafting team respectfully disagrees and declines to make your suggested changes.**		
ACES Power Marketing Standards Collaborators	No	In general, we are supportive of the list and requirement because it helps to clarify what changes are intended in Part 1.1.3 in Requirement R1. However, we have identified two specific issues with the list. (1) First, we question if this requirement is at least partly duplicative with FAC-001-0 R2.1.2 which requires the TO to have procedures for notification of new or modified equipment.

Organization	Yes or No	Question 5 Comment
		(2) Second, the third bullet regarding additions, removals, and replacements of transmission system Elements is too broad. This literally means that if a TO replaces a bus section with similar equipment, this requirement to notify of changes is triggered which then triggers a Protection System Study or documentation that one is not required per Requirement R1 Part 1.1.3. Ultimately, we believe the changes that need to be identified are those that actually affect the Protection Systems for the Interconnected Facilities or those that change the Fault current on the Interconnected Facilities. (3) The 30 day requirement should be struck from Part 3.2. If a schedule is not identified by any party, it must not be pressing and an artificial deadline should not be created. (4) The language of the main requirement needs to be further refined. A literal reading would require the TO, GO, and DP to provide details about Interconnected Facilities that they neither own nor operate or to which they are even connected. Obviously, the literal meaning is not intended. The requirement needs to be refined to clarify that the TO, GO, and DP only need to provide the details for Facilities they own. (5) For Part 3.3.2, we suggest clarifying that this requirement does not apply if the equipment is replaced with like equipment and settings. (6) We also suggest that that some sort of exemption is written into this part for extreme weather events that allows more time for notifications.

Response: Thank you for your comment

1. **While FAC-001 Part R2.1.2 does require the Transmission Owner to have a procedure, the drafting team believes the two requirements are not duplicative. PRC-027-1 Requirement R3 requires the communication of Protection System information between owners of Interconnected Elements.**
2. **Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be**

Organization	Yes or No	Question 5 Comment
communicated. **3. The drafting team believes that 30 days is a sufficient time to reply to a request for information; however, the requirement provides flexibility to negotiate an extended schedule.** **4. The drafting team revised Requirement R3 for clarification, indicating that the owner shall provide details to only Responsible Entities connected to the same Interconnected Element.** **5. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."** **6. The drafting team believes that 30 calendar days is sufficient and adequate to provide the notice and declines to make a change.**		
Kansas City Power & Light	No	Bullet item #3 is too broad. The NERC Glossary definition for Element is, "Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.". For example, a disconnect switch would be considered an Element, but a change of this component would not warrant a change to relay protection. Recommend modifying bullet item #3 to, "Additions, removals, or replacements of transmission system Element(s) that have an impact on relay protection systems or component(s)"
Response: Thank you for your comment. **Based on your and other comments, the drafting team revised Requirement R3 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.**		
Southern Company	No	Reference the bullet on Line items; the issue of mutual coupling and/or overhead grd wire replacement or changes should be included. Perhaps change to any change that impacts the positive, or zero sequence impedance.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **Based on your and other comments, the drafting team revised Requirement R3 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.**		
Western Area Power Administration	No	1. What are the details to be provided? 2. Should only be for significant changes.
Response: Thank you for your comment **1. The drafting team believes that the examples of the provided information are clear but leave flexibility between the two parties.** **2. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.**		
Flathead Electric Cooperative, Inc.	No	Comments: R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward
Response: Thank you for your comment **Requirement R2 requires the Transmission Owners to perform the Fault current studies because they have the necessary information to perform the studies. Requirement R1 requires all applicable entities to perform Protection System Studies. Requirement R3 requires all applicable entities to exchange the information necessary for Protection System coordination.**		
Manitoba Hydro	No	(1) It is not clear what this list should include. Should the protection changes on the interconnected facilities only be included? Or should it include the protection

Organization	Yes or No	Question 5 Comment
		changes on the adjacent elements? (2) Also, for the changes of power system elements, should those connected directly to the interconnecting bus be included or it should also include changes beyond that?
Response: Thank you for your comment **1. The drafting team believes Protection System changes at other Facilities that modify the conditions used in the coordination of Protection Systems of the Interconnected Elements need to be communicated because they could lead to coordination issues.** **2. The drafting team believes changes at other Facilities that modify the conditions used in the coordination of Protection Systems of the Interconnected Elements need to be communicated because they could lead to coordination issues. An example of this is a new substation installed near Interconnected Elements that could require a change in impedance relay settings for overreaching zones.**		
LCRA Transmission Services Corporation	No	(1) Requirement R3 should read: Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System shall provide to each directly impacted Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility, the details (e.g., project schedule, protective relaying scheme types and settings) as follows: (2) The first bullet of requirement R3.1 should read: New installation, replacement with different types, or modification of: protective relays or protective function settings that result in a direct impact on protection system coordination to an entity at that Interconnected Facility. (3) The second bullet of requirement R3.1 should read: Changes to positive or zero sequence line impedance by more than 5 percent
Response: Thank you for your comment **1. The drafting team believes that the Applicability section appropriately describes which entities and for which installations**		

Organization	Yes or No	Question 5 Comment
require exchange of data. **2. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available. (3) Based on your comment and others, the second bullet of Requirement R3, Part 3.1 was modified (and combined with the third bullet). However, the drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.**		
Exelon	No	In the current draft of PRC-027-1, Requirement 3.1 mandates that for any of the listed network changes, entities must communicate "the details", (i.e., design information to all entities that share the interconnection). Of the network changes/additions listed in the draft, however, some may result in little or no changes to existing protection system coordination settings, thereby having no impact to Protection Systems of other entities. For example, consider a project by a TO to replace a BES circuit breaker at an Interconnected Facility. Assume that breaker failure protection for that circuit breaker will also be upgraded, but that the settings and all protection functions for the new relay remains unchanged from the old system. According to the language of Requirement 3.1, the TO would be required to transmit design information to other entities associated with the interconnected facility even though the project would have no impact to the other entities. This represents one example of a frequently performed project in which design information is not presently shared between entities at an Interconnected Facility. Mandatory compliance with this requirement, as written, could represent a significant burden to the industry by requiring unnecessary communication of design details to other entities, in addition to the added compliance documentation activity, and having no impact to protection systems of the recipients. Exelon suggests that the SDT clarify Requirement 3.1 such that that if a change to an Interconnected

Organization	Yes or No	Question 5 Comment
		Facility is not expected to result in a change to the desired sequence of Protection System operations , the compliance activities required by R3.1 should be waived
Response: Thank you for your comment. **Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.** **In your specific example, the drafting team believes that, if the proposed breaker failure protection change does not modify the impedances used in the calculation of fault currents, then the information does not need to be exchanged.**		
Tacoma Power	No	1. This list does not appear to sufficiently address BES transformers (e.g., autotransformers). 2. There is concern that R3.1 may introduce either an administrative burden to identify and track every change, including those that would not reasonably impact Protection System coordination, or compliance jeopardy if those changes are not identified and tracked. a. For example, the second bullet under R3.1 refers to changes to line spacing. Assume that, during restoration following a Fault, a damaged insulator on one pole or tower is replaced with an insulator one inch longer. Technically, this changes the line spacing. It is doubtful that the SDT intended that this or a similar but less trivial scenario would trigger a Protection System Study; however, the language may introduce compliance jeopardy. Perhaps a similar metric as used in R2.3 could be applied to the second, third, fourth, and fifth bullets. For example, perhaps a 5% change in interconnecting Element impedance from a baseline could trigger a Protection System Study; this approach could be used in lieu of the second and fifth bullets. It seems that R2.3 would address the third and fourth bullets if the short circuit study were conducted before the change was implemented. b. Additionally, the language in the first bullet under R3.1 may introduce compliance jeopardy. For instance, it is possible for an entity to adjust a current and/or voltage

Organization	Yes or No	Question 5 Comment
		transformer ratio and compensate with one or more relay settings such that the primary settings do not change. In many of these cases, there will be no impact on Protection System coordination. While active communication among entities is advised, the potential for fines in this type of scenario does not seem to be appropriate. The emphasis on the first bullet under R3.1 should be on Protection System scheme (e.g., distance, overcurrent, DCB, POTT, differential), primary settings (including time delays), independence/redundancy, and technology (primarily for communications systems).
Response: Thank you for your comment **1. The drafting team believes that BES transformers are addressed in the original third bullet, which is now combined into the second bullet, of Requirement R3, Part 3.1.** **2a. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** **In your specific example, the drafting team believes that the type of damage replacement that you suggested is so small that it would not modify the impedances used in the calculation of fault currents and would therefore not need to be communicated to the interconnecting entity. Part 3.1 does not trigger a Protection System Study.** **2b. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the type of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.**		
Public Service Enterprise Group	No	a. R3 should be rewritten as follows: "Each Transmission Owner, Generator Owner, and Distribution Provider shall provide the following to each Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility:" b. Part 3.1 should be modified as follows: "For any change or additions listed below,

Organization	Yes or No	Question 5 Comment
		provide a project schedule and the reason for the project, whether to an existing or new Interconnected Facility or to other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities:" c. Part 3.2 does not read well and is not supported by the explanation in the text box. It references 1.1.1, 1.1.2, and 1.1.3, but none of these parts allow an Interconnection Facility owner to request information from another owner to perform the Protection System Study. We can understand why Interconnection Facility owners need to cooperate in the performance of such studies. This thought belongs in R1. We suggest a new 1.2 (with the existing 1.2 renumbered to 1.3) as follows: "Each Interconnected Facility owner shall provide data requested by another owner and which is needed to perform the study in 1.1, either in accordance with an agreed-upon schedule, or within 90 days of receiving the request." We believe 30 days is too short to require a response.
Response: Thank you for your comment **a. Requirement R3 was reworded to enhance clarity.** **b. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** **c. The drafting team believes that nothing in the requirements precludes an entity from asking for necessary data, and requirements are needed to ensure that requested data is provided. The drafting team believes that 30 calendar days is sufficient and adequate to provide the response, and declines to make a change.**		
Liberty Electric Power LLC	No	The phrase "Changes to generator unit(s), including replacements, re-ratings, and impedances" is too vague. Audit teams could read any change as a trigger. Suggested change: "following the replacement or re-rating of a generator, or following any change to a generator which results in a change in impedance".

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **The drafting team has made your suggested change.**		
Ameren	No	We recommend the following changes to Requirement 3- (1) Include 'static wire' in the second bullet, or more simply state as 'line impedance changes.' (2) Include 'bus arrangement changes' in the third bullet. (3) Change the fourth bullet to include 'Additions, retirements, or changes...' to strive for consistency for generation and transmission.
Response: Thank you for your comment **1. Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.** **2. The drafting team believes that "bus arrangement changes" would be included in the revised second bullet of Requirement 3, Part 3.1.** **3. The drafting team believes the existing language is clear with regard to generation and respectfully declines to make the change.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	No	Ingleside Cogeneration LP believes that the coordination process developed by the project team is redundant with the one established in FAC-002-1. If there is a material change made to a Facility, the process should be captured in a single reliability standard.
Response: Thank you for your comment. **FAC-002-1 does not address Protection System coordination and the drafting team does not believe the two standards are redundant. As described in the "Description of the Current Draft," PRC-027 is replacing PRC-001, Requirements R3 and R4.**		

Organization	Yes or No	Question 5 Comment
Georgia Transmission Corporation	No	1. The parenthetical comment in R3 should be deleted. R3.1 lists the items that would trigger the need for notification between entities. Once notified of modifications, the entities will communicate documentation needs. 2. R3.2: In the case of major BES equipment failure, there is a more pressing need to notify an interfacing entity that there has been change that could affect fault magnitudes. The 30 calendar days may be too long for such occurrences and 2 business days would be more in consideration. 3. R3.3.1 may interfere with PRC-004-# time schedules for misoperation follow-ups and investigations. 4. R3.3.2: Refer to comment above regarding R3.2.
Response: Thank you for your comment 1. **The drafting team believes that the parenthetical expression is beneficial to Requirement 3, but it was moved to Part 3.1 for clarity.** 2. **Requirement 3, Part 3.2 regards responding to a request for information required to perform a Protection System Study, not for notification of an unplanned change in the BES configuration.** 3. **The drafting team believes that the notifications of Requirement 3, Part 3.3 will not impact schedules for any future version of PRC-004 because the notifications take place after the corrective action has been implemented.** 4. **Requirement 3, Part 3.2 regards the failure of Protection System components and their replacement, not BES Elements that can change the fault duty.**		
Wisconsin Electric Power Company	No	1. R3 should have the phrase “shall notify...” in the requirement, not simply “shall provide ...the details”. This should be a requirement for entities to provide a notification to other entities that some changes are being planned which may affect Protection System coordination. 2. The wording in R3.1 is unclear as to the intended scope of the qualifying phrase, “when the proposed change modifies the conditions used in the coordination of

Organization	Yes or No	Question 5 Comment
		Protection Systems of the Interconnected Facilities." It should be made clear that ONLY those changes which affect coordination need to be communicated to other entities, whether at new or existing Interconnected Facilities or other facilities. If this is the case, then some of the comments below may not apply. 3. Also in R3.1, the bullets for "changes" in transmission systems and generators should be modified by the word "significant". Likewise, a "replacement" of an Element, or relay, or other device, may not require any change in relay settings, so the wording should be modified by "replacements which require protection setting changes". The bullet for changes to generators should also remove the "re-ratings" term, since a re-rating of a generator typically affects output power, but does not change the impedance. Indeed, there may be many minor changes which fall in the current R3.1 list which may have little or no effect on fault coordination, and therefore should not trigger a requirement for a notification or a study. Also, changes to CT or VT ratios do not necessarily result in a change in primary quantities, so these references should be removed. 4. R3.2 should be revised to require an entity making significant changes to provide the data to the other affected entities, without the need for the other entities to request it. 5. The R3.3 requirement (3.3.1 and 3.3.2) to notify other entities within 30 days for changes made following a Misoperation or failure is too restrictive. A timeframe of 60 days would be more appropriate. Also, as above, these requirements should only be applicable when the changes made have a "significant effect on coordination." A requirement to make notifications for changes unrelated to Interconnected Facility coordination will not serve the objective of increased reliability, and only increases unnecessary compliance documentation. 6. M7 (last phrase) should be revised to "...or absent such an agreement, within 30 calendar days of a request."
Response: Thank you for your comment		

Organization	Yes or No	Question 5 Comment
1. **The drafting team believes that providing the details of the changes is more beneficial than just notifying of a proposed change.** 2. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** 3. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** 4. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** 5. **The drafting team believes that 30 days is a sufficient time to reply to provide the information on the changes.** 6. **Based on your comment, Measure M6 (old M7) was modified to read, "Acceptable evidence for R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was provided according to the agreed-upon schedule, or absent such an agreement, within 30 calendar days of a request."**		
Lincoln Electric System	No	LES is concerned with the significant amount of data and information an entity would be required to share as part of R3. As an example, if a CT ratio on a secondary relay with no pilot tripping is changed, but does not change the intended response of that relay, then there is no reason to share that information simply for the sake of sharing it. Entities should be allowed some amount of discretion regarding the information to be shared amongst other entities.
Response: Thank you for your comment **The drafting team believes that communication between interconnecting entities is important for any change that modifies the**		

Organization	Yes or No	Question 5 Comment
information previously used to comply with Requirement R2, regardless of the type of change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.		
Portland General Electric Company	No	No, Add facility ratings and define transmission line impedance tolerance (see question 9 response)
Response: Thank you for your comment. **The drafting team believes that FAC-009 already requires the sharing of Facility Ratings and their inclusion into the Protection System coordination standard is unnecessary. Your concern relating to PRC-023 is valid and may need to be addressed in FAC-009 or PRC-023.** **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.**		
American Transmission Company	No	ATC does not agree with the list as written and recommends the following changes: (1) ATC suggests that Requirement 3.1 bullet 2, be revised as follows: Changes to line lengths and/or conductor size or spacing that result in significant impedance changes. As an example, an interconnected line may need to relocate a pole because of a road move. This may alter slightly the length or spacing of the line but does not result in a change to the impedance. If no impedance change occurred, no relay settings need to be changed and there should be no additional coordination. (2) ATC suggests that Requirement 3.1 bullet 3, be revised as follows: Additions, removals, or replacements of transmission system Element(s) that is significant. An Element may be replaced with an equivalent device that does not require a relay setting change. If no relay settings need to be changed, there should be no additional coordination.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment
1. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.
In your specific example, since the impedance did not change the drafting team believes you would not need to inform each Responsible Entity connected to the same Interconnected Element.
2. Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.</td></tr>
<tr><td>NPPD</td><td>No</td><td>Section 3.3 should clarify if the corrections change the coordination then other entities should be notified.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: “Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.”</td></tr>
<tr><td>Utility Services</td><td>No</td><td>This requirement if left as is, would create a potential double jeopardy situation if a violation occurs. Under FAC-002, entities already have the obligations to communicate and coordinate the integration of new, replacement, or upgrades on existing facilities. We view this requirement to be a duplication of that standard and creates a double jeopardy situation if a violation were deemed to have occurred.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment
FAC-002-1 does not address Protection System coordination and the drafting team does not believe the two standards are redundant. As described in the “Description of the Current Draft,” PRC-027 is replacing PRC-001, Requirements R3 and R4.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
mason	No	Do not agree with blanket inclusion of replacement of the generator step-up transformer(s) on this list.
Response: Thank you for your comment. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available. It is the experience of the drafting team that modeling information will change with the replacement of a transformer.**		
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency (IMEA) recommends language be included in R3 (and elsewhere if needed) to clarify the R3.1 "generator unit(s)" is not applicable to a 20 MVA or less unit or behind-the-meter generation.
Response: Thank you for your comment **This is an issue that reaches beyond the scope of this standard and may need to be addressed through a Request for Interpretation. However, the Applicability section indicates that an entity that is registered as a Generator Owner and has Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements will need to comply with this standard.**		
Trans Bay Cable	No	Comments: R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward.
Response: Thank you for your comment **Requirement R2 requires the Transmission Owners to perform the Fault current studies because they have the necessary information to perform the studies. Requirement R1 requires all applicable entities to perform Protection System Studies. Requirement R3 requires all applicable entities to exchange the information necessary for Protection System coordination.**		

Organization	Yes or No	Question 5 Comment
CenterPoint Energy	No	(a) Requirement 3 includes providing schedule information and project details to generation entities. There may be established market rules that provide for what information can be shared with competitive entities. (b) Requirements 3.1 and 3.3, with examples of what system and equipment changes require coordination, appear overly broad. Such requirements should only be "if applicable". R3.1, for example, specifies changes in line length. Certain changes of line length are immaterial to protection system set points. (c) R3.3 requires coordination for the replacement of failed equipment. Replacing equipment "like function-for-like function" should be excluded from this requirement.
Response: Thank you for your comment a. **The drafting team does not believe that the requested exchange of information would violate the Standards of Conduct for an entity registered as both a GO and a TO.** b. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** **In your specific example, the drafting team believes that the entities involved can agree whether the change is significant enough to warrant an immediate review of the Protection System or whether the change could just be added to the simulation model for review as a part of the fault current assessment specified in Requirement R2.** c. **Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Duke Energy	No	(1) Revise second bullet under R3.1 as follows: "Changes to line impedance". (2) Add another bullet under R3.1 as follows: "Changes to breaker failure scheme

Organization	Yes or No	Question 5 Comment
		operating times”. (3) Also, we don’t agree with the R3.1 Rationale that specifying a single time frame is inappropriate. A time frame similar to R3.2 should be specified. We suggest the following revised lead-in paragraph to R3.1: “According to an agreed-upon schedule or absent such an agreement, 180 calendar days prior to implementing any change or additions listed below; either at an Interconnected Facility or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities”.
Response: Thank you for your comment 1. **Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.** 2. **The drafting team believes that breaker failure scheme timers are already included from the first bullet.** 3. **The drafting team respectfully disagrees and declines to make your suggested changes.**		
South Carolina Electric and Gas	No	R3.3 in its entirety should be removed considering that all conditions covered by R3.3 are already covered by R3.1 which states: “New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios” If a correction or replacement of a protection system element is made per R3.3, this is the same thing as a modification covered under R3.1. It is noted that R4 would need to be reworded to accommodate unplanned and emergency protection system changes.
Response: Thank you for your comment **The purpose of Requirement R3, Part 3.3 is to allow retroactive notification when changes are made during events such as commissioning or component failure.**		

Organization	Yes or No	Question 5 Comment
ExxonMobil Research & Engineering	No	
Sacramento Municipal Utility District	Yes	(1) We agree with the list in R3.1. (2) We feel that R2, R3.2 and R3.3 are unnecessary. Instead, the list in R3.1 should act as a trigger requiring both entities to document communication agreeing that coordination exists prior to putting the changes into effect. No communication under R3.3 should be required if the changes restore the system to its original state - replacing a failed relay like for like.
Response: Thank you for your comment **1. Thank you for your support.** **2. Requirement 3, Part 3.2 is associated with providing information required to perform Protection System Studies, which may be required outside of a change in 3.1. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Public Utility District No. 1 of Snohomish County	Yes	(1) Comments: SNPD agrees with the list in R3.1. (2) We feel that R2, R3.2 and R3.3 are unnecessary. Instead, the list in R3.1 should act as a trigger requiring both entities to document communication agreeing that coordination exists prior to putting the changes into effect. No communication under R3.3 should be required if the changes restore the system to its original state - replacing a failed relay like for like.
Response: Thank you for your comment **1. Thank you for your support.** **2. Requirement 3, Part 3.2 is associated with providing information required to perform Protection System Studies, which may be required outside of a change in 3.1. Based on your and other comments, the drafting team revised Requirement R3, Part**		

Organization	Yes or No	Question 5 Comment
3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."		
Dominion (this vote was changed to No, per Connie Lowe's email with updated comment submission)	No	a). Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout the draft already address notification requirements. By using the term project scheduling this implies that detailed project information needs to be included in the information exchange. The standard should not dictate the information exchange details required and should allow the entities to determine what information is required in the exchange in order to achieve protection coordination in the appropriate timeframe. b). In R3 reword to read: "Each Functional Entity shall provide to other Functional Entities connected to an Interconnected Facility, the details of the Protection System as follows:" (It is not necessary to include (e.g. Examples) since references to these are already listed in R3-3.1.) c). In R3-3.1 reword to read: "When adding new or modifying existing Interconnected Facilities or when making changes to other facilities where the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities" d). Bullets: 1st bullet -Recommend changing reference to "protective Function settings" to "protection settings"./ 2nd bullet – Reword to read: "Line impedance changes" / 3rd bullet – Remove the word "system" e). In R3-3.3.1 change Requirement to read: "Changes found during Misoperation, commissioning, or maintenance activities that modify the conditions used in the coordination of Protection Systems. "
Response: Thank you for your comment		

Organization	Yes or No	Question 5 Comment
a. The drafting team believes it is necessary to share the pertinent scheduling information that could affect the other party. b. The drafting team believes the current wording more correctly states the requirement. c. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available. d. The drafting team believes the first bullet accurately portrays the requirement's needs. e. Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated. f. The drafting team combined the 3rd bullet of Requirement R3, Part 3.1 with the 2nd bullet but the drafting team did not believe that "system" needed to be removed. g. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."		
National Grid USA / Niagara Mohawk	Yes	
Imperial Irrigation District (IID)	Yes	
Detroit Edison	Yes	
MRO NSRF	Yes	
ISO RTO Council SRC	Yes	
Progress Energy	Yes	

Organization	Yes or No	Question 5 Comment
Salt River Project	Yes	
Operational Compliance	Yes	
Pacific Gas and Electric Company	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
Idaho Power Company	Yes	
City of Austin dba Austin Energy	Yes	
Texas Reliability Entity	Yes	
Xcel Energy	Yes	
Tri-State G & T	Yes	
NV Energy	Yes	
Dairyland Power Cooperative	Yes	
Platte River Power Authority	Yes	
MWDSC	Yes	

Organization	Yes or No	Question 5 Comment
ATCO Electric	Yes	
El Paso Electric Company	Yes	
Clark Public Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
El Paso Electric	Yes	

6. In Requirement R4, the SDT required that agreement must be reached prior to implementation of proposed Protection System changes except under the conditions identified in Requirement 3, Part 3.3. Do you agree with this need? If not, please specify reasons in the comment area.

Summary Consideration:

A majority of commenters concurred with the need for entities to confirm agreement of Protection System coordination prior to implementing changes. Several commenters expressed a desire to see the standard drafting team develop and include a conflict resolution process for situations where mutual agreement cannot be reached. The drafting team responded with the following: The drafting team believes that any conflict resolution should be handled through normal company practices.

Several commenters expressed concern that Requirement 4 seemed to mandate agreement without provision for the entity receiving study results to express disagreement and suggest modifications or compromise. Also some commenters disagreed with the time frames associated with Requirement 4, suggesting lengthening them and/or including a provision for an otherwise agreed-upon schedule. Others suggested the "prior to implementation" was appropriate without specifying any particular time period. Based on comments, the drafting team revised Requirement R4, Parts 4.1 and 4.2, and removed Part 4.3. The responses are as follows: Based on comments, the drafting team revised Requirement R4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Also based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."

Some commenters suggested the requirement refer to entities confirming "acceptance" rather than confirming "agreement". Others suggested the requirement refer to agreeing that coordination is achieved or maintained prior to implementing changes, rather than requiring agreement with the changes themselves. Based on these comments, the drafting team revised Requirements R4, Parts 4.1 and 4.2 as noted above.

Organization	Yes or No	Question 6 Comment
Southwest Power Pool NERC Reliability Standards	No	1. We agree with the need but feel it needs to be more detailed to include wording that would address that the coordinated owner has all appropriate data to

Organization	Yes or No	Question 6 Comment
Development Team		perform the study before his 30 day timeline begins. 2. We would also like to see a conflict resolution process included under this requirement.
Response: Thank you for your comment. **1. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.** **2. The drafting team believes that any conflict resolution should be handled through normal company practices.**		
Pepco Holdings Inc. & Affiliates	No	1) Requirement R4 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What if agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R4.2 until agreement is reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D

Organization	Yes or No	Question 6 Comment
		subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? 2) Requirement R4.3 requires confirmation of agreement within 30 days of being notified of corrections made due to as found setting errors or emergency replacements of Protection System components. Again, what if the changes are not acceptable to the other party? Which entity is found not compliant, the one who proactively made the changes or the one who won't confirm agreement? This is the problem with mandating that an agreement between two parties be reached. It is further compounded by requiring that an agreement be reached within a set timeframe. 3) It is important to ensure that information on new, or modified, Protection Systems are shared between parties, so that each party may assess the impact of the change and ensure their Protection Systems are properly set and coordinated. The emphasis should be on sharing of information (such as relay setting changes) and not the details of performing the "Protection System Study" and all the associated approval schedules. As such, it may be reasonable to have a Reliability Standard to ensure setting information has been exchanged (which was the original intent of the PRC-001-1 standard). But it should be left at that. Mandating mutual agreement with compliance implications, without providing some outlet for a dispute resolution process seems unfair to either party. As such, we suggest Requirement R4 be removed entirely or extensively re-written to address the concerns outlined above.

Response: Thank you for your comments.

1. **The drafting team believes that any conflict resolution should be handled through normal company practices. The drafting team cannot make judgments on compliance.**
2. **The drafting team believes that any conflict resolution should be handled through normal company practices. The drafting**

Organization	Yes or No	Question 6 Comment
team cannot make judgments on compliance. 3. The drafting team believes that any conflict resolution should be handled through normal company practices. The drafting team believes Requirement R4 is an integral part of the standard and must remain.		
Luminant	No	Luminant agrees with the need to reach an agreement on relay coordination based on the specific circumstances in R3.3.1 and R3.3.2. However, the time period to reach agreement of 30 days should be replaced with an agreed upon time schedule by all parties.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Bonneville Power Administration	No	In many cases, one party of the interconnection is simply implementing the protection system changes provided by the other entity. Requiring the agreement of this party implies that the entity understands what is going on and is not a practical use of time and resources.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Detroit Edison	No	Recommend that if protection system changes due to emergencies need not be agreed upon before installation, then this should be stated more directly in the standard.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td>Western Small Entity Comment Group</td><td>No</td><td>R4.1 as written apparently requires receiving entities to always agree with the initial study, even if they see flaws that would lead to miscoordinating Protection Systems. Suggest that “confirm” be replaced with “reach.”</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>MRO NSRF</td><td>No</td><td>1) The NSRF agrees in general but questions how to handle situation where neighboring utility are unable or unwilling to meet required timetable? Recommend the SDT explain the process for conflict resolution.

2) Requirement 4.2 seems to mandate agreement with proposed changes which seems to go beyond the scope of the standard which is stated as “to coordinate Protection Systems”. It is suggested that this requirement be rewritten to require agreement that proper coordination will be maintained when the changes are implemented.

3) In a similar way requirement 4.3 should be rewritten.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

1. The drafting team believes that any conflict resolution should be handled through normal company practices.

2. Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”

3. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.</td></tr>
<tr><td>PPL Corporation NERC</td><td>No</td><td>See comment in question #1 above.</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
Registered Affiliates		
Response: Thank you for your comment. **Please see the drafting team response to your comment in Question 1.**		
Colorado Springs Utilities	No	This requirement seems to create a paper work burden that will add cost and lengthen the process of any and all transmission changes, unless there is some size significance added to the requirement under which a reduced process is involved. The maximum amount of paper work to complete must be assumed, unless there are specific limits set to restrict an overreach in how the regulation is applied.
Response: Thank you for your comment. **The drafting team believes the scope of a particular project will dictate the work necessary to coordinate the Protection Systems involved, and to document the coordination process.**		
Associated Electric Cooperative, Inc., JRO00088	No	PRC-027-1 R4.2 change: Replace: “that Protection Systems(s) changes” With: “each related Protection Systems(s) change “Rationale: AECI sympathizes with the need for agreement, and believes that to be the necessary goal. However, this requirement indicates all-or-none for notified Protection System Change(s). Entities may agree on most all communicated changes, and yet a more complicated change, particularly outside of Zone 1, may require some interim compromise, or that one particular (backward-looking) be excluded until agreement is reached. Full agreement, prior to placing facilities into service, might otherwise become a method for forcing a poor compromise on protective settings.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s)**		

Organization	Yes or No	Question 6 Comment
associated with Requirement R3, Part 3.1, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."		
Southern Company	No	If there is a requirement to agree, what happens if there is no agreement. There must be a resolution process.
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal company practices.**		
Independent Electricity System Operator	No	We agree with the need to provide an agreement to the study results and to confirm acceptability of the proposed changes (other than those conditions identified in Requirement 3, Part 3.3), but R4 is unclear in a number of aspects, as follows: 1. 4.1 There is no requirement or provision for the receiving entities to express disagreement, with rationale, and R4 does not require resolving the differences. Both need to be added. 2. 4.2 Based on the language in Part 4.1, we assume R4 applies to the receiving entities. Hence we interpret 4.2 to require the receiving entities to confirm with the sending (or the initiating) entities of their agreement with the proposed changes. In that vein, the wording in 4.1 "confirm the affected Interconnected Facility owners" is unclear as to who needs to confirm with whom. Suggest to reword 4.1 to:"Prior to the in-service date of any planned change at the Interconnected Facility, confirm with the Interconnected Facility owners that initiated the changes that agreement with the Protection System(s) changes as described in Requirement R3, Part 3.1. was reached." 3. 4.3 requires that the receiving entities confirm with the initiating entities of the changes made under Part 3.3, for which prior agreements are not necessary or perhaps possible. However, there is no requirement or provision for the receiving entities to express a disagreement, with rationale, and suggest alternative setting

Organization	Yes or No	Question 6 Comment
		changes, or resolve the differences. This needs to be provided.
Response: Thank you for your comment. 1. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."** 2. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."** 3. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
American Electric Power	No	The 90 Day window will not be sufficient during the initial R1 time frame. AEP suggests 180 days during the R1 compliance window.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
City of Austin dba Austin Energy	No	Austin Energy (AE) agrees with the need to coordinate Protection System changes; however, AE believes R4.2 is not sufficiently clear. As written, one could interpret it to mean that a Facility owner must obtain consent on the changes listed under R3.1, not just the Protection System changes (such as relay settings). AE does not believe it appropriate to require a Facility owner to gain consent on the actual change to the Facility itself (such as changes to line lengths/conductor size or replacement of transmission system Element(s), generator units or generator step-up transformer).The Guidelines and Technical Basis (p 20 of PRC-027-1 Draft #1) states, "The purpose of this requirement is to assure the effects

Organization	Yes or No	Question 6 Comment
		that planned changes have on Protection Systems at Interconnected Facilities have been considered by all affected entities." AE agrees with this concept and believes the SDT sufficiently covers it through R1.1.3 and R4.1. AE recommends striking R4.2 from the Standard.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s)associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		
LCRA Transmission Services Corporation	No	Each Transmission Owner, Generator Owner, and Distribution Provider shall: 4.1. Within 90 calendar days after receipt, confirm acceptance with the summary results of a Protection System Coordination Study, as described in Requirement R1, Part 1.2. 4.2. Prior to the in-service date of any planned change at the Interconnected Facility, confirm the affected Interconnected Facility owners accept the Protection System(s) changes, as described in Requirement R3, Part 3.1
Response: Thank you for your comment. **1. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."** **2. Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		
Tri-State G & T	No	We believe that there are many instances of changes that can made to Protection Systems as required in Requirement 3, Part 3.1 that don't require coordination between entities but that might be interpreted that the change "modifies the

Organization	Yes or No	Question 6 Comment
		conditions used in the coordination of Protection Systems." Examples are load encroachment settings, communication port settings, etc. We think language needs to be added with regard to "... modifications that impact the coordination of Protection Systems between entities, of: ..." in the first bullet, if confirmation from the other entity is required.
Response: Thank you for your comment. **The drafting team believes that any change(s) noted in Requirement R3, Part 3.1 at the Interconnected Element needs to be communicated with the other entity.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	No	In general, Ingleside Cogeneration LP believes that a material unplanned change must be communicated to neighboring Facility Owners. However, this should not include an emergency replacement in kind due to a failure. This is a repair only which does not change the characteristics of the relay or the associated BES components - and therefore has no impact on interconnected owners.
Response: Thank you for your comment. **The drafting team believes this information must be communicated.**		
Wisconsin Electric Power Company	No	The requirement to reach agreement on Protection System changes prior to the project in-service date is not realistic and should be removed. While the entity that is initiating a project has a responsibility under R3 to notify other entities in order to perform a study, there is no required timeframe for these notifications to occur. Unless the initiating entity has a requirement to provide data under R3 in a timeframe sufficiently ahead of the in-service date, this is a requirement that may be impossible to achieve.
Response: Thank you for your comment. **The drafting team believes that proposed modifications to Interconnected Elements, as described in Requirement R3, Part 3.1,**		

Organization	Yes or No	Question 6 Comment
must be communicated and agreed to prior to the in-service date. This would include communication of project schedules developed relative to a project's scope. However, the drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated for a particular project. Further, the drafting team believes the entity initiating the project has incentive to consider provision of, and response to Protection System coordination issues be considered within the project schedule. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		
Dairyland Power Cooperative	No	How is it to be handled if two entities do not agree to the same approach?
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal company practices.**		
Portland General Electric Company	No	No, see question 9 response
NPPD	No	Recommend the drafting team should consider several scenarios to help determine issues that will arise with putting into practice this standard with the time lines included. Some scenarios I can think of are: 1. who is liable or fineable if a required approval reply for a protection study is not made in a timely manner to a Transmission owner. It is imperative not to hold a utility responsible for another entities lack of timely responses. These issues will create murky situations when the Transmission owner does not have control over external entities ability to respond to notifications of changes within specified times. 2. If a Distribution Provider is not registered is the Transmission owner responsible for getting a reply or approval of a protection study?
Response: Thank you for your comments.		

Organization	Yes or No	Question 6 Comment
1. **The drafting team cannot make compliance judgments. Additionally, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."** 2. **The standard is only applicable to the registered entities listed in the Applicability section of the standard.**		
Utility Services	No	See comment to Question 5.
mason	No	Each entity has its own philosophy and standards for Protection System design. In providing agreement to a third party design, a question of liability is also opened up. R4 should be changed from requiring agreement to requiring notification. There is enough incentive for entities to resolve material disagreements on Protection System design without the need for regulatory intervention. Regulatory involvement should only take place when business conditions call for it. Otherwise the result is higher production costs with no reliability benefit.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Trans Bay Cable	No	Comments: R4.1 as written apparently requires receiving entities to always agree with the initial study, even if they see flaws that would lead to miscoordinating Protection Systems. Suggest that "confirm" be replaced with "reach."
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Clark Public Utilities	No	1. The proposed Requirement R4 is not an acceptable method of confirming

Organization	Yes or No	Question 6 Comment
		agreement among parties. Requirement 4.1 requires an entity to agree with the proposed changes within 90 calendar days. What if the entity thinks the proposed changes are wrong? Other standards that require entity A to provide information to entity B provide that entity B will provide written comments to entity A within a specified period of time. 4.1 should state the following: "Within 90 calendar days after receipt, provide written comments (if any) regarding the summary results of a Protection System Study, as described in Requirement R1, Part 1.2." 2. Requirement 4.2 will require an entity needing to implement a planned change to delay the in-service date until affected entities agree with the proposal. This sets up a potential stand-off with no method of resolution. In other standards where parties provide comments the entity is required to respond to those comments within a specified period of time. However, 4.2 as worded would stop the implementation until the other parties all agree. The owner of the facility needs to have ultimate and sole control for implementing these changes and the current 4.2 would stop a project dead in its tracks until the other parties all agreed. Proceeding without this agreement would result in a standard violation and imparts power upon entities over facilities they do not own. 4.2 should state the following: "Within 30 calendar days after receipt of any written comments received per Requirement 4.1 and prior to the in-service date of any planned change at the Interconnected Facility, respond to such written comments."

Response: Thank you for your comment.

1. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**
2. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**

Organization	Yes or No	Question 6 Comment
Oncor Electric Delivery Company LLC	No	Oncor believes agreements must be reached; however, there needs to be some definitions in the Standard to define the exact meaning of the term “agreement”. In addition, the sub requirements 4.3.1 and 4.3.2 calls for confirmation of the Protection System changes are acceptable pursuant to notification received in Requirement 3, within 30 days, however the sub requirements provide no mechanism for resolution in the event the changes are not acceptable to the receiving entity within 30 days of receipt. Oncor suggest that these two sub requirements be removed. There are sufficient checks and balances under 4.2 to provide coverage for any disagreement between entities without the need to self-report under the 4.3.1 and 4.3.2 if an agreement cannot be reached within 30 days of receipt.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
ExxonMobil Research & Engineering	No	
Northeast Power Coordinating Council	Yes	What happens when consensus is not reached between two parties? The TO should have the responsibility for coordination.
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal company practices.**		
ACES Power Marketing Standards Collaborators	Yes	Yes, we agree. The application guidelines were particularly helpful in explaining how the Requirements R3 and R4 work together.
Response: Thank you for your comment.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td>Operational Compliance</td><td>Yes</td><td>We suggest that R4.1, R4.3.1 and R4.3.2 all have a time period of 90 days.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.</td></tr>
<tr><td>Sacramento Municipal Utility District</td><td>Yes</td><td>We agree that the entities should agree prior to any changes being implemented. The only date of interest, in our opinion, is the in-service date of any proposed changes. If agreement is reached prior to the field changes being made, then that is all that matters.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”</td></tr>
<tr><td>Xcel Energy</td><td>Yes</td><td>1. Conceivably, there could be non-reliability based reasons why an entity might not provide concurrence. An alternate avenue should be considered as allowable, such as the requesting entity working through the RC to obtain response from a non-responsive entity.

2. Similar comments on measure M9 as contained in item 3 above on measure M2.

3. Measure M9 does not account for non-acceptance under R4.3 or R4.1 as restudy or expanded studies may be required and result in a M9 violation.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

1. The drafting team believes that any conflict resolution should be handled through normal company practices.

2. Acceptable evidence that response was provided could be registered mail confirming receipt at an address. Additional acceptable evidence would be letters, or emails acknowledging receipt.</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
3. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."		
Exelon	Yes	Comments: Although not stated explicitly, this question seems to be asking about R4, Part R4.2. Exelon agrees that concurrence should be reached prior to the in service date for Protection System changes that result from the equipment changes at an Interconnected Facility as described in R3, Part3.1.
Response: Thank you for your comment.		
Duke Energy	Yes	1. We support the necessity for agreement, but there can be differences in philosophies that make reaching agreement difficult. How are disagreements to be handled? 2. As the requirement is currently worded, the entity receiving the study has no alternative but to agree within the specified timeframes.
Response: Thank you for your comment. 1. The drafting team believes that any conflict resolution should be handled through normal company practices. 2. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."		
Dominion	Yes	
National Grid USA / Niagara Mohawk	Yes	
Hydro One	Yes	

Organization	Yes or No	Question 6 Comment
Imperial Irrigation District (IID)	Yes	
Santee Cooper	Yes	
SERC Protection and Control Subcommittee	Yes	
ISO RTO Council SRC	Yes	
Tennessee Valley Authority	Yes	
GP Strategies	Yes	
Kansas City Power & Light	Yes	
Salt River Project	Yes	
Pacific Gas and Electric Company	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Idaho Power Company	Yes	
Texas Reliability Entity	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 6 Comment
Liberty Electric Power LLC	Yes	
Ameren	Yes	
Georgia Transmission Corporation	Yes	
NV Energy	Yes	
Platte River Power Authority	Yes	
MWDSC	Yes	
American Transmission Company	Yes	
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
El Paso Electric Company	Yes	
South Carolina Electric and Gas	Yes	
El Paso Electric	Yes	
FirstEnergy		No answer or comment at this time.
Public Service Enterprise		a. In R4 overall, we concur that agreement does need to be reached before changes

Organization	Yes or No	Question 6 Comment
Group		can be implemented; however, if there is a disagreement that cannot be resolved by the parties within the time frames specified, a dispute resolution process should be invoked. Otherwise, if an owner disagrees with another owner's results, it has no option but to agree or face a violation of the standard for failing to do so. b. The specific requirement in the question is in part 4.2, not R4. The list of items in R3.1 appeared reasonable. But R4.2 requires agreement to be reached "prior to the in-service date" under R4.2. Allowing agreement to be reached prior to the in-service date could allow one party to unreasonably hold up the schedule. It should be stated as follows: "Within 90 days after receiving the planned changes at the Interconnection Facility, the affected Interconnection Facility owners shall either agree with the changes, or propose alternative changes, stating why such changes are desirable. Failure to provide a response will constitute agreement with the planned changes by the non-responding Interconnecting Facility owner."
Response: Thank you for your comment. **a. The drafting team believes that any conflict resolution should be handled through normal company practices.** **b. Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		
Public Utility District No. 1 of Snohomish County		Comments: SNPD agrees that the entities should agree prior to any changes being implemented. The only date of interest, in our opinion, is the in-service date of any proposed changes. If agreement is reached prior to the field changes being made, then that is all that matters.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		

7. **In Requirement R4, the SDT established a 90 day time frame for responding to a request for agreement with a Protection System Study. Do you agree with this time frame? If not, please provide specific suggestions with your reasoning(s) in the comment area.**

Summary Consideration:

The responses were equally split between agreeing and not agreeing with the 90 day time frame. Some comments wanted a longer time frame due to resource issues while others preferred a shorter time frame to prevent potential project delays. The drafting team decided not to make any changes to the time frame and responded as such: The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Element(s) to review the summary results of a Protection System Study.

There were several comments which suggested changes to the requirements. The responses included one or more of the following:

- Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."
- Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."
- Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.

Several responses involved the need for a resolution process in cases that agreement could not be reached. The drafting team responded to these comments as follows: "The drafting team believes that any conflict resolution should be handled through normal company practices".

Organization	Yes or No	Question 7 Comment
Pepco Holdings Inc. & Affiliates	No	We suggest Requirement R4 be removed entirely or extensively re-written to address the concerns outlined in our response to Question 6.
Response: Thank you for your comment.		

Organization	Yes or No	Question 7 Comment
Based on comments, the drafting team did extensively rewrite Requirement R4 including removing Requirement R4, Part 4.3.		
Luminant	No	Luminant recommends that the time frame should be "according to an agreed-upon documented schedule between Transmission Owner, Generation Owner, or Distribution Provider. Luminant would recommend the removal of the 90 day requirement. 90 days may not fit all circumstances. It should be left between the parties to determine the timeline of the project and reaching agreement. This is what should be documented to ensure coordination of activities between the affected parties.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Imperial Irrigation District (IID)	No	120 calendar days are suggested instead of 90 because verification of Protection System Study needs to be performed before an agreement can be made and it is time consuming.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Bonneville Power Administration	No	BPA believes that requiring an agreement from all parties could prevent the implementation of emergency changes.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Detroit Edison	No	It appears that the "initiator" has 90 days after completing the study to provide the information while the other entity has 90 days to review and respond to the request. Suggest that a longer response time frame be considered since the "responder" may need significant time to review changes.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
PPL Corporation NERC Registered Affiliates	No	See comment in question #1 above.
Colorado Springs Utilities	No	Due to construction schedule requirements a 30 day approach should be taken.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Tennessee Valley Authority	No	There may be instances where extenuating circumstances delay agreement beyond 90 days. For long lead time or complex protection scheme projects requiring more

Organization	Yes or No	Question 7 Comment
		interaction between protective relaying engineers, exceeding the 90 day period could be acceptable to the entities involved. Evidence of mutual agreement on an extension beyond 90 days should be acceptable.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
ACES Power Marketing Standards Collaborators	No	We assume this question refers to Part 4.1. While we do not see any issues with the 90 day requirement, Part 4.1 needs to be modified to reflect what a responsible entity must do if they do not agree. As written any other response than agreement is a violation. Thus, if a TO indicates it disagrees with the results of the Protection System Study (PSS) within 90 days, it technically is in violation of the requirement. The application guidelines explain that absent agreement the revisions should be proposed. We agree with this approach but the requirement simply does not say this. It should.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Kansas City Power & Light	No	These can be matters of extreme complexity in design, implementation and operation. Stipulating that 90 days (Requirement 4.1) and 30 days (Requirement 4.3) is sufficient time to come to an agreement is presumptuous and is not necessary. Requirements 4.1 and 4.3 should stipulate that entities in receipt of proposed

Organization	Yes or No	Question 7 Comment
		changes to relay protection system(s) or component(s) be evaluated and responded to by the entity in receipt. The response could be agreement or non-agreement with concerns or objections noted in the response.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." The drafting team also combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Southern Company	No	Within "90 calendar days after receipt, confirm agreement" vs. "90 day time frame for responding to a request". Acknowledgement of the receipt and review of a change should be the limit here - agreement with the settings should not be required.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Salt River Project	No	This is too long; 60 days should be adequate
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		

Organization	Yes or No	Question 7 Comment
Pacific Gas and Electric Company	No	12 month time frame may be required to resolve the technical issues that typically prevent agreement
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Western Area Power Administration	No	See general comments below (#9).
American Electric Power	No	AEP has suggested adjusting the time requirements, as stated in Question 3 and 7. These time requirements should be included and the VSLs should be scaled accordingly.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Sacramento Municipal Utility District	No	No, we do not agree. R4.2 should apply here. R4.1 and R4.3 should be eliminated. If one entity proposes making settings changes, then agreement must be reached prior to implementing the changes. We feel all these timelines are unnecessarily burdensome to remember and quite arbitrary. If one entity believes it cannot get another entity to respond or to reach agreement on coordination, they can always ask their RE for assistance in maintaining the reliability of the system. Since all these activities occurred long before the mandatory standards existed and are covered

Organization	Yes or No	Question 7 Comment
		under the present PRC-001, we do not feel the REs will be swamped with calls if R4.1 and R4.3 are eliminated.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.” Also based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”**		
City of Austin dba Austin Energy	No	Austin Energy (AE) believes that 90 days is sufficient for responding to summary results of a Protection System Study, but it is not always sufficient for completing the iterative discussions that often take place to resolve questions and potential concerns. The Guidelines and Technical Basis (p19 of PRC-027-1 Draft #1) states, “R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to confirm agreement with the summary results of a Protection System Study ...; or absent such agreement, propose revisions to achieve acceptable results.” AE asks the SDT to include this “absent such agreement” concept in R4.1 and extend the timeline to accommodate such revisions to one that is mutually agreed upon by the impacted parties.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”**		
Manitoba Hydro	No	This 90 day time frame may be too long, since an agreement is required from the

Organization	Yes or No	Question 7 Comment
		interconnecting parties before the proposed protection changes can be implemented.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Exelon	No	This question differs from what is required in the language in the draft standard. In Requirement R4.1, the 90 days allowed is for entities to "confirm agreement" with the summary. If an entity must only respond at the end of 90 days, the response could be that they disagree. In this case, discrepancies must be resolved at the cost of more time. Regardless, allowing 90 days for an entity to respond before an entity can proceed with design could cause serious delays to engineering and design processes. However, until we know what is required by a Protection System study, Exelon cannot offer a suggestion for a suitable timeframe for R4.1. SDT should specifically justify the proposed 90-day time frame. Since, a 90-day time frame may not be sufficient to compile all the required design data and results for Protection System Study (PSS) and to verify the Protection Systems are coordinated within the applicable entities.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Tri-State G & T	No	We think 60 days is more appropriate. For the receiving party, 30 days may be too short, and for the sending party 90 days may be too long.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Liberty Electric Power LLC	No	Smaller entities do not have the staff resources to respond, and must bid, contract, and receive a report. Further, they must also go through a process to allocate the funds. 180 days at a minimum, but ideally a longer period should be in place to allow for the budget process.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Public Utility District No. 1 of Snohomish County	No	Comments: SNPD does not agree. R4.2 should apply here. R4.1 and R4.3 should be eliminated. If one entity proposes making settings changes, then agreement must be reached prior to implementing the changes. We feel all these timelines are unnecessarily burdensome to remember and quite arbitrary. If one entity believes it cannot get another entity to respond or to reach agreement on coordination, they can always ask their RE for assistance in maintaining the reliability of the system. Since all these activities occurred long before the mandatory standards existed and are covered under the present PRC-001, we do not feel the REs will be swamped with calls if R4.1 and R4.3 are eliminated.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after**		

Organization	Yes or No	Question 7 Comment
receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Also based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."		
Platte River Power Authority	No	We believe the agreement must be reached prior to implementing the changes. This requirement is burdensome on the entity for record keeping and does not add reliability to the BPS.
Response: Thank you for your comment. **Based on comments, the drafting team did extensively rewrite Requirement R4 including removing Requirement R4, Part 4.3.**		
MWDSC	No	More time than 90 days may be needed to reach agreement for complex system changes or because of conflicting study priorities. Allow more flexibility for the parties to agree to a time, not to exceed, e.g. 180 days.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Portland General Electric Company	No	No, It depends upon what constitutes a Protection System Study (see question 9 response
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1,**		

Organization	Yes or No	Question 7 Comment
Part 1.2, and respond as to whether further action is required.”		
American Transmission Company	No	1) ATC does not agree with the 90 day time frame. 2) ATC also has the following recommendation: Requirement 4.2 states that Interconnected Facility Owners confirm that coordination is agreed to prior to placing equipment in-service. ATC believes that R4.2 is adequate to cover coordination. Therefore, the SDT should strike R4.1 and R4.3.
Response: Thank you for your comment. **1. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”** **2. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”**		
NPPD	No	This requirement does not allow for various scenarios or conditions in the process of doing business. For example, multiple phased work or longer lead time projects where designs may change. It would be better that there be verification that studies were performed prior to in-service dates rather than tracking detailed time lines which could likely be complex and difficult to judge for audit start and end dates.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”**		

Organization	Yes or No	Question 7 Comment
mason	No	Do not agree with the need for documentation of "agreement with a Protection System Study" between entities. See Question 6 response.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
El Paso Electric Company	No	1) EPE believes the timelines are not adequate when coordinating protection system studies involving sequential interdependence among parties for interconnected facilities. Timing of study data should correlate with any written agreements or procedures agreed to between the various parties. EPE also believes the documentation requirements within this draft Standard slow down the process, therefore increasing the time needed to complete and communicate the study data. 2) Additionally, the proposed Standard fails to address two important and likely types of situations: (a) the situation in which an interconnected entity fails to respond to study results or to a planned change at the Interconnected Facility, or (b) the situation in which disagreements between the entities are not resolved within the proposed Standard's time clock.
Response: Thank you for your comment. **1. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		

Organization	Yes or No	Question 7 Comment
2. The drafting team believes that any conflict resolution should be handled through normal company practices.		
El Paso Electric	No	1) EPE believes the timelines are not adequate when coordinating protection system studies involving sequential interdependence among parties for interconnected facilities. Timing of study data should correlate with any written agreements or procedures agreed to between the various parties. 2) EPE also believes the documentation requirements within this draft Standard slow down the process, therefore increasing the time needed to complete and communicate the study data. The proposed Standard fails to address two important and likely types of situations: (a) the situation in which an interconnected entity fails to respond with study results or to a planned change at the Interconnected Facility, or (b) the situation in which disagreements between the entities are not resolved within the proposed Standard's time clock.
Response: Thank you for your comment. 1. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."** 2. **The drafting team believes that any conflict resolution should be handled through normal company practices.**		
ExxonMobil Research & Engineering	No	
Utility Services	No	
National Grid USA / Niagara Mohawk	Yes	1) In the event that someone hands you a study of their entire system or of all their interconnections you should only be responsible for reviewing study results for those interconnections in which you are a participant.

Organization	Yes or No	Question 7 Comment
		2) Furthermore, what if you don't agree with the study results you've been handed? The text as written literally commands you to agree with them! The text should be reworded to require a response (not necessarily agreement) within 90 days and relative only to the portion of the study applicable to interconnections you participate in.
Response: Thank you for your comment. **1. The drafting team believes the purpose and applicability sections of the standard support your conclusion.** **2. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Northeast Power Coordinating Council	Yes	For studies of an entire system or all of its interconnections, those persons doing the study should only be responsible for reviewing the study results for those interconnections in which they participate. The wording in the text demands that the results be agreed with. The text should be reworded to require a response (not necessarily agreement) within 90 days and only pertain to the portion of the study applicable to interconnections participated in.
Response: Thank you for your comment. **The drafting team believes the purpose and applicability sections of the standard support your conclusion. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Associated Electric Cooperative, Inc., JRO00088	Yes	These facilities take time and budget to build or implement, and so 3-months prior to field-changes seems reasonable.
Response: Thank you for your comment.		

Organization	Yes or No	Question 7 Comment
Idaho Power Company	Yes	Yes, There appears to be no mechanism in the Requirement addressing if coordination changes are not acceptable. This should be addressed as 90 days could easily be exceeded in this scenario.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
South Carolina Electric and Gas	Yes	1) R4.1 only mentions R1. 2) R4.2 should be reworded to make it clear that entities have 90 days to respond to proposed protection system changes received per R3.1. The concern is that with no specified time the responding entity can delay the initiating entity's schedule even if the protection system changes were shared well in advance of the in service date.
Response: Thank you for your comment. **1. Requirement R4, Part 4.1 is intended to only reference Requirement R1.** **2. The drafting team acknowledges your concern and believes the concern you raise would need to be handled through normal company practices.**		
Dominion	Yes	Reword R4., 4.3 to read: <u>"Within 30 calendar days after receiving notification of:"</u>
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		

Organization	Yes or No	Question 7 Comment
Southwest Power Pool NERC Reliability Standards Development Team	Yes	
Hydro One	Yes	
Santee Cooper	Yes	
Western Small Entity Comment Group	Yes	
MRO NSRF	Yes	
SERC Protection and Control Subcommittee	Yes	
ISO RTO Council SRC	Yes	
GP Strategies	Yes	
Operational Compliance	Yes	
Independent Electricity System Operator	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Texas Reliability Entity	Yes	
LCRA Transmission Services	Yes	

Organization	Yes or No	Question 7 Comment
Corporation		
Xcel Energy	Yes	
Tacoma Power	Yes	
Ameren	Yes	
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	Yes	
Georgia Transmission Corporation	Yes	
Wisconsin Electric Power Company	Yes	
NV Energy	Yes	
Dairyland Power Cooperative	Yes	
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
Trans Bay Cable	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 7 Comment
Clark Public Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
FirstEnergy		No answer or comment at this time.
Public Service Enterprise Group		See our response to #6 above, paragraph a.

8. **The team included VRFs, VSLs, and Time Horizons with this posting. Do you agree with the assignments? If not, please provide specific suggestions for change.**

Summary Consideration:

In general, most commenters agreed with the VRF assignments and about half of the commenters agreed with the VSLs assignments. Those commenters that disagreed with several of the assigned VSLs stated that they were too stringent, or escalated too rapidly. Several commenters wanted consistency regarding the time frames established for tardiness.

The drafting team responded that they had assigned the VRFs and written the VSLs in accordance with the guidance established by NERC and FERC, and that the VSLs were assigned based upon the significance of the individual requirement parts to the overall coordination process. The drafting team made no changes to the VRFs; however, the following changes were made to the VSLs:

- For Requirement R1, Part 1.1.2, the time period for tardiness in the 'Lower' VSL was lengthened from 10 days to 30 days.

One commenter suggested adding Long-term Planning to the Time Horizon for Requirement R3. The drafting team agreed and made the suggested change.

Organization	Yes or No	Question 8 Comment
Luminant	No	Based on the comments on Q6, the VSL would need to be modified. Q7 and 9, the VSLs would change accordingly to accommodate an agreed-upon time frame for acceptable relay coordination and a method for resolving issues surrounding obtaining an acceptable coordination where differences occur.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		

Organization	Yes or No	Question 8 Comment
Bonneville Power Administration	No	BPA believes that in general, the VRFs and VSL's are too high.
Response: Thank you for your comment. **The drafting team assigned the VRFs in accordance with the NERC criteria and FERC guidelines for establishing VRFs, and believes the assigned risk factors are appropriate.**		
Santee Cooper	No	The 10 day VSLs are too restrictive in R1.1.1. VSL times should be similar for all requirements. Suggest dates should be as follows: Lower - 30 days late, Moderate - more than 30 days, less than a year, High - more than a year, but completed, Severe - more than a year or not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Detroit Edison	No	The proposed VSL for R4 appears to imply that the "receiving" entity has no other choice but to confirm agreement. If the "receiving" entity has concerns with the study or changes, both parties should be responsible for resolving the issues.
Response: Thank you for your comment. **The drafting team believes your comment pertains to Requirement R4 and not the VSL. Requirement R4 does require the receiving entity to confirm agreement within a set time frame. The VSL defines the degree of non-compliance with the requirement.**		

Organization	Yes or No	Question 8 Comment
Western Small Entity Comment Group	No	We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in “guidelines and Technical Basis” that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team’s intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
PPL Corporation NERC Registered Affiliates	No	See comment in question #1 above.
SERC Protection and Control Subcommittee	No	We recommend a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale, this urgency is not warranted. Most entities will have numerous Interconnection Facilities, so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: o Lower VSL should be 30 days late. o Moderate VSL should be more than 30 days, less than a year. o High VSL should be more than a year but done. o Severe VSL should be more than a year and not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs; and believes the VSL for Requirement 1, Part 1.1.1 is correctly assigned. The drafting team modified Requirement 1, Part 1.1.1 to 48 months from 36**		

Organization	Yes or No	Question 8 Comment
months. The VSLs are written specific to an individual requirement and define the degree to which compliance with the requirement was not achieved; consequently, a consistent set of VSL time frames across all requirements may not be appropriate. The drafting team strives for consistency in assignment of VSLs throughout the standard.		
Colorado Springs Utilities	No	If the requirements are not reasonable, the VRFs and VSLs are also not reasonable.
Response: Thank you for your comment.		
Tennessee Valley Authority	No	We recommend a consistent set of VSL timeframes across all requirements. The 10 day limits are unreasonable and, as stated in the R1.1.1 rationale, this urgency is not warranted. Most entities will have numerous Interconnection Facilities, so applying these VSLs to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: o Lower VSL should be 60 days late. o Moderate VSL should be more than 60 days, less than a year. o High VSL should be more than a year but done. o Severe VSL should be more than a year and not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Associated Electric Cooperative, Inc., JRO00088	No	See SERC PCS Comments.
ACES Power Marketing Standards Collaborators	No	(1) The time horizon for R2 should only be Long-term Planning. The study has to be completed every 24 months and while notification in Part 2.3 has to occur within 30

Organization	Yes or No	Question 8 Comment
		days it is only after that the study to satisfy the 24 month time period is complete. (2) Requirement R3 should include Long-term Planning. Transmission system expansions would be covered under Part 3.1. (3) The VSLs for Requirement R1 are gradated based on the number of days late the requirement is met for Part 1.1 but not Part 1.2. It seems Part 1.2 should have similar gradated VSLs. (4) For Requirement R4, we suggest the VSL for Part 4.2 should clearly state that any changes made during extreme operating circumstances (i.e. extreme weather) are excluded. This is essentially a question on what is meant by “planned”. Are changes made to restore service in a hurricane or tornado damaged area a few days after the devastation planned? We think they are not but see how auditors could view the changes as planned particular if any level of study was required.

Response: Thank you for your comment.

The Time Horizon is a compliance element and is used as a factor in determining the size of a sanction. If an entity violates a requirement and there is no time to mitigate the violation because the requirement takes place in real-time, then the sanction associated with the violation is higher than it would be for violation of a requirement that could be mitigated over a longer period of time.

1. **The drafting team respectfully disagrees and believes the time horizons are appropriate and consistent with the criteria for establishing time horizons: Long-term Planning — a planning horizon of one year or longer... Operations Planning — operating and resource plans from day-ahead up to and including seasonal.**
2. **The drafting team agrees and will make the suggested change to Requirement R3.**
3. **Please review the VSLs. Requirement 1, Part 1.2 is already gradated.**
4. **The notification of unplanned changes (for circumstances as you describe) are covered by Requirement 3, Part 3.3. The drafting team has removed the requirement for parties to reach agreement (Requirement R4, Part 4.3).**

Organization	Yes or No	Question 8 Comment
Kansas City Power & Light	No	The 10 day increments represent a 5% error and considering this is a six month requirement. The 10 day increment represents 4 - 6 working days across 2 weekends and including a holiday. Recommend the increments be increased to allow at least 10 working days which would be at least 15 calendar day increments. VSL for R2, part 2.1 - The 10 day increments represent a 1% error and considering this is a 24 month requirement. Recommend the increments be increased to 30 days to make more sense with the 24 month period.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Pacific Gas and Electric Company	No	do not line up with probability and potential severity
Response: Thank you for your comment. **The drafting team assigned the VRFs in accordance with the NERC criteria and FERC guidelines for establishing VRFs, and believes the assigned risk factors are appropriate.**		
Flathead Electric Cooperative, Inc.	No	Comments: We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in "guidelines and Technical Basis" that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
ReliabilityFirst	No	ReliabiltiyFirst beleives the VRF for Requirement R4 should be High since it requires completion of the coordination activities. Lack of coordination of Protection Systems can result in larger scale outages.
Response: Thank you for your comment. **The drafting team disagrees and believes the VRF for Requirement R4 more aligns with the NERC criteria for a medium risk.**		
LCRA Transmission Services Corporation	No	Objectives of R2 and R4 are mostly associated with interchange of information and the associated Violation Risk Factor for these two requirements (R2 and R4) should be LOW.
Response: Thank you for your comment. **The drafting team respectfully disagrees and believes the VRFs for Requirements R2 and R4 align with the NERC criteria as established. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner, and reaching agreement on Protection System settings and schemes. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur.**		
Ameren	No	We recommend to the SDT that a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale this

Organization	Yes or No	Question 8 Comment
		urgency is not warranted. Most entities will have numerous Interconnection Facilities so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: (a) Lower VSL should be 30 days late. (b) Moderate VSL should be more than 30 days, less than a year. (c) High VSL should be more than a year but done. (d) Severe VSL should be more than a year and not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Portland General Electric Company	No	No, Severe VSL for lateness should only apply to R4.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs and believes the assigned VSLs are appropriate.**		
American Transmission Company	No	The VSLs, in general, are much more severe than the risk to the BES and should be rewritten to more accurately reflect the risk. For example: if a BES Element is replaced "like for like" with no material impact to the associated settings and a failure to notify by more than 30 days occurs, the issue is assigned a Severe VSL yet there

Organization	Yes or No	Question 8 Comment
		was no effective change to BES reliability.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. Note, in your example, if it is an exact "like for like" replacement with no setting changes – no notification would be required as this would not be covered by the standard; however, any replacement with a different style and/or changes of settings would be applicable under this standard and require notification.**		
NPPD	No	The time lines monitored down to 10, 20 or 30 days appear to be impractical in terms of monitoring for facility owners and in terms of auditing by compliance entities. This diverts the focus or sharing the data in a timely manner prior to project in service dates.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Trans Bay Cable	No	Comments: We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in "guidelines and Technical Basis" that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.
Response: Thank you for your comment.		

Organization	Yes or No	Question 8 Comment
The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.		
Duke Energy	No	The requirements in this standard do not have solely one activity. Also, requirements R1, R2, and R4 do not have an activity or goal stated (other than is stated in the subparts). The requirements in this standard all have sub-requirements, multiple measures and VSLs consisting of various combinations of non-compliance with sub-requirements. We think the standard could be made clearer by separating sub-requirements out as separate requirements with their own measure and VSLs.
Response: Thank you for your comment. **The drafting team considered your suggestion and declines to make the suggested changes to the standard content.**		
Oncor Electric Delivery Company LLC	No	Until 'agreement' definitions or further clarity as to what is an "agreement", can be added the Standard, Oncor does not believe that VRFs and VSLs can be established for this standard.
Response: Thank you for your comment.		
ExxonMobil Research & Engineering	No	
Liberty Electric Power LLC	No	
Dominion	No	Dominion recommends a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale this urgency is not

Organization	Yes or No	Question 8 Comment
		warranted. Most entities will have numerous Interconnection Facilities so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: • Lower VSL should be 30 days late. • Moderate VSL should be more than 30 days, less than a year. • High VSL should be more than a year but done. • Severe VSL should be more than a year and not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Independent Electricity System Operator	Yes	We generally agree with the VRFs and the VSLs for the requirements as presented, but we have concerns with some of the requirements and hence reserve our comments until we see revisions made to these requirements.
Response: Thank you for your comment and support.		
Texas Reliability Entity	Yes	In the Severe VSL for R4.3, the word "entity" was left out after "The responsible . . ."
Response: Thank you for your comment. The error was corrected.		
Georgia Transmission Corporation	Yes	Meets NERC time frame practice.
Response: Thank you for your comment and support.		

Organization	Yes or No	Question 8 Comment
Southwest Power Pool NERC Reliability Standards Development Team	Yes	
National Grid USA / Niagara Mohawk	Yes	
Hydro One	Yes	
Imperial Irrigation District (IID)	Yes	
Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
ISO RTO Council SRC	Yes	
Operational Compliance	Yes	
Idaho Power Company	Yes	
City of Austin dba Austin Energy	Yes	
Manitoba Hydro	Yes	
Exelon	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 8 Comment
Tri-State G & T	Yes	
NV Energy	Yes	
Dairyland Power Cooperative	Yes	
MWDSC	Yes	
ATCO Electric	Yes	
Clark Public Utilities	Yes	
South Carolina Electric and Gas	Yes	
Pepco Holdings Inc. & Affiliates		No Comments
FirstEnergy		No answer or comment at this time.
Public Service Enterprise Group		Did not evaluate.
mason		No comment

9. **If you have any other comments that you have NOT provided in response to the above questions, please provide them here. (Please do not repeat comments that you provided elsewhere.)**

Summary Consideration:

Some commenters wanted the drafting team to further modify PRC-001-2 by adding a Measure for Requirement R1 or retire the standard. This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, "The drafting team recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".

Some commenters requested the time frame in Requirement 2, Part 2.1 be increased up to 60 months to coincide with studies associated with TPL-001-2 draft 5 Requirement R2, Part 2.6.1. The drafting team responded with the following: "The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require."

Numerous commenters wanted further clarification as to the definition of a Protection System Study and also what is included in a summary result. Other commenters did not want the term Protection System Study added to the NERC Glossary of Terms. The drafting team declined to modify the definition of the Protection System Study but did add the following to the description in the "Guidelines and Technical Basis": "System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions." The drafting team believes that the full description in the Guidelines and Technical Basis is now adequate and appropriate. The drafting team did add language to the standard to specify that the term Protection System Study will not be added to the NERC Glossary of Terms. "The following terms are defined for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the Glossary of Terms:"

Some commenters expressed concern over the number of time frames associated with the coordination process and the burden of documentation. The drafting team believes the assigned time frames and documentation are appropriate and necessary and declined to make any changes.

Numerous commenters wanted the description associated with Figure 3 clarified. The drafting team noted that: Figure 3 is independent of whether the facilities are part of the BES. The intent is to identify that the coordination is required where Protection Systems are installed for the purpose of protecting Transmission System Elements. The drafting team added a note of clarification of the phrase

"Protection Systems installed to detect faults on the BES Transmission System." Figure 3 represents a generator connected to a Distribution Provider. The drafting team revised the description relating to Figure 3 in the "Guidelines and Technical Basis" to clarify that only the Distribution Provider's Protection Systems installed to protect for Faults on Transmission System Elements are a part of the Applicability of this standard. The drafting team modified Figure 3 to indicate that the source could be a generator or a network system.

A few commenters suggested the Figures in the Application Guidelines needed clarification on what the Interconnected Facilities were in the Figures. The drafting team modified the text associated with each Figure to identify the Interconnected Elements.

Some commenters expressed concern over the need to provide evidence demonstrating that the information was received by the other entity. The drafting team modified Measures M6, M7 and M8 to indicate the evidence needed is dated documentation that the information was provided during the specified time frames.

Several commenters suggested changes to the process flow chart and the drafting team modified the flow chart to be consistent with the requirements.

A few commenters wanted time frames to be established for Requirement R1, Part 1.1.3. The drafting team reiterated that there in not a single time frame that would be appropriate for every project and chose not to modify the standard.

Several commenters wanted Requirement R4 to be revised because of compliance and agreement concerns. The drafting team revised the requirement for clarity.

Several commenters requested the Applicability Section 4.2 Facilities be modified to clarify the role of Distribution Providers. The drafting team responded that they believe the Distribution Providers that own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements should be included in the Applicability of this standard because those Protection Systems must be coordinated with the Protection Systems of other Facility owners.

A commenter requested clarification of the Fault current contribution specified in Requirement R2, Part 2. The drafting team modified Requirement R2, Part 2.2 to read "for the interconnecting bus(s) under consideration."

A commenter expressed concern that Requirement R2 mandated that an entity perform a short circuit study even if no Protection System Study existed. The drafting team modified Requirement R2, Part 2.1 to read: "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."

Several commenters suggested various changes be made to the Purpose statement of the standard. Based on these comments, the drafting team modified the Purpose to read: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults." and also modified Requirement R1, Part 1.1 to reflect the change in the Purpose. It now reads: "Perform a Protection System Study for each Interconnected Element to coordinate Protection Systems, such that the least number of power system Elements are isolated to clear Faults as follows:"

Organization	Yes or No	Question 9 Comment
ACES Power Marketing Standards Collaborators		(1) Please restate section 4.2. It states that it applies to Protection Systems installed at Interconnected Facilities. "Installed at" is not really the intention. It should be Protection Systems installed to protect Interconnected Facilities. While they most likely would be at the Facility, they do not have to be. For example, a 500 kV transmission line is a Facility. Protection Systems will not be "Installed at" the line but rather at the substations. (2) If PRC-001-3 R1 is going to be retained, it needs to be further refined. a) First, it inappropriately uses the term area when referring to a GOP. While the BA and TOP do have Balancing Authority Areas and Transmission Operator Areas, no equivalent exists with the GOP. The GOP simply operates generating units not areas. b) Second, the requirement confuses the role of the GO and GOP. In the functional model, it is the GO that is responsible for installing, setting and coordinating generation protection systems not the GOP. Thus, it is not clear what role the drafting team envisions for the GOP being familiar" with the purpose and limitation of protection system schemes applied in its area". c) Third, the requirement is written too broadly for the BA. Because the requirement compels the BA to be familiar "with the purpose and limitation

Organization	Yes or No	Question 9 Comment
		of protection system schemes applied in its area" this could literally require the BA to understand many protection schemes for which it has no direct or even indirect responsibility. For instance, distance and differential protection schemes are contained within the metered boundaries of a BA Area. This requirement would compel the BA to be familiar with them even though this knowledge would have zero impact on its decision making or responsibilities. This does not align with the responsibilities assigned to the BA in the functional model. The BA being included in this requirement is likely a vestige of the version 0 standards and should be corrected. When version 0 standards were translated from the policies, BA and TOP were simply substituted for control area regardless of the role the control area was playing in the requirement. (3) The NERC function model defines one role of the Transmission Planner as "define system protection and control needs". Should the Transmission Planner have a role in this standard? For instance, should the TP actually perform the short circuit studies? (4) The application guidelines and examples are very helpful in understanding the intent of the drafting team. However, we recommend revising the example regarding Figure 3. It would appear to assume a distribution level generator is part of the BES and subject to NERC standards. While it is possible for a generator on the distribution system to be part of the BES (i.e. if it is a Blackstart Resource), inclusion of such a generator would be unusual and an exception to the normal BES 100 kV threshold. If the generator is not part of the BES, there would be no Generation Owner registered to perform the coordination. Industry is likely to be sensitive to such an example. Removing the generator will still allow the example to communicate that a breaker and associated Protection System on the high side (100 kV or higher) of a distribution or step-down transformer would still have to be coordinated.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. 1. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."** 2. **This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, "The drafting team recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".** 3. **Although the Transmission Planner may "define system protection and control needs", it will be the owner that is responsible for determining the implementation and coordination.** 4. **Figure 3 is independent of whether the facilities are part of the BES. The intent is to identify that the coordination is required where Protection Systems are installed for the purpose of protecting Transmission System Elements.**		
Ameren		(1) We support and agree with the SERC Protection & Control Subcommittee comments. (2) We commend the SDT on their high quality initial draft of PRC-027-1. (3) We recommend that the SDT delete 'operating' from the Interconnected Facilities definition because their different functional or corporate entities sufficiently capture all of them. We also suggest defining the singular Interconnection Facility, rather than the plural. (4) The SDT needs to improve the application guidance examples by stating what constitutes the Interconnection Facility. The first example clearly enumerates the short circuit locations and values to be compared between the most recent Protection Study and the R2 2.1 value. (5) Application Guidelines Example / Figure 3: The Note should be clarified, or the example should be removed. In terms of regulatory requirements, Breaker-A and B should coordinate with Breaker-C. However, Breaker-C and the Generator relaying does not need to coordinate with Breakers at Station-1 or Station-2 unless the

Organization	Yes or No	Question 9 Comment
		generator meets the requirements of a BES element (75MW or greater). For small generators, protection on the generator to detect faults on the transmission system is for generation protection, not BES protection; as the fault currents would be too small to cause damage to the Transmission System. Generator protection is already covered in Example / Figure #2. (6) Please restate Effective Date more clearly, we suggest "PRC-027-1 shall become effective on the first day of the first calendar quarter [delete-that is] three months following [delete-beyond the date that this standard is approved by] applicable regulatory approvals [delete-authorities],..." to be consistent with the wording of other standards (e.g. PRC-005-2.) (7) Since short circuit data base models are required to perform the Protection System Study, NERC regions should have a consistent schedule for revising models. Please encourage regions to synchronize their regional modeling calendars to enable entities to have consistent models, especially near region borders, for efficient execution of PRC-027-1 (8) we recommend that the SDT add proposed NERC Standard TPL-001-2 to your list on page 5 regarding the Other Aspects of coordination. It requires short circuit studies in R2.8 for the purpose of determining if the short circuit interrupting requirements are within the interrupting capabilities of circuit breakers. (9) We strongly recommend that the SDT use the term 'change' rather than 'deviation' throughout for consistency and because the latter term is defined as being different from the norm. The new fault current value is now the norm, not abnormal or statistically different. R1 - 1.1.2 and 1.1.3 use 'change', but 'deviation' is then used about a dozen times thereafter in the document. (10) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process.

Organization	Yes or No	Question 9 Comment
		(a) The overall process would be less burdensome by changing the R2 2.1 to “not less than once every 5 calendar years” which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3.(b) The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. (b) Omitting ‘project schedule’ from R3 would streamline data exchange. (c) R3-3.1 and 3.3.1 should only be required IF the changes effect the tripping or coordinated functions. Digital relays include numerous settings besides these functions; and these other settings should not trigger a data exchange or study. (d) Streamline the process by measuring dates an entity sends information and receives final agreement. It is burdensome for the sending entity to also track and retain evidence showing another entity received information. Specifically change M2, M5, M6, M7, and M8 to measure the date sent. The other entity’s agreement in M9 shows that the overall process met overall time requirements and that the entities coordinated. If an entity demonstrates such a study is not required in R1, M1 should require the other entity to agree. (e) The application guidelines are generally clear and certainly clarify responsibility. We recommend somehow including their methodology in the requirements because it streamlines the exchanged data and clarifies the process in this complex and potentially voluminous undertaking.

Response: Thank you for your comment.

1. **See the response to the SERC Protection & Control Subcommittee comments.**
2. **Thank you for your support.**
3. **Based on comments, the drafting team modified Interconnected Facilities to Interconnected Elements defined as follows,**

Organization	Yes or No	Question 9 Comment
Interconnected Elements: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity. 4. The drafting team has modified the figures to clarify what is the Interconnected Element. 5. Figure 3 is independent of whether the facilities are part of the BES. The intent is to identify that the coordination is required where Protection Systems are installed for the purpose of protecting transmission system elements. The drafting team has modified Figure #3. 6. The language for the Effective Date is the authorized text approved by NERC legal staff. 7. This is outside the scope of the drafting team. 8. The drafting team believes that the referenced requirement in TPL-001-2 is related to interrupting capabilities and is not directly related to Protection System coordination. 9. The drafting team believes that the term "deviation" is properly used in R2 Part 2.2 and is synonymous with the term "change". 10. (a) The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require. (b) The drafting team believes that omitting the "project schedule" from the list of example data submittal will not streamline the data exchange, but the schedule is very likely required to ensure that each entity can allocate resources as necessary. (c) Requirement R3, Part 3.1 states that the information shall be provided "when the proposed change modifies the conditions used in the coordination of Protection Systems…" The drafting team modified Requirement R3, Part 3.3 to eliminate Parts 3.3.1 and 3.3.2, but believes any information previously provided to another entity to ensure Protection System coordination must be provided if any of the information is changed pursuant to Part 3.3. (d) The drafting team believes that confirmation of receipt is an important aspect of information exchange and declines to		

Organization	Yes or No	Question 9 Comment
make the suggested change. **(e) The drafting team believes that the "Guidelines and Technical Basis" is the appropriate place to elaborate on the responsibilities under the standard rather than including the information in the Requirements.**		
TransAlta Centralia Generation LLC		1) Applicability 4.2 Facilities should be Protection System installed at Interconnected Facilities that required coordination. 2) R2- For the Inteconnected Faculties only for the purpose of the generator interconnection, only the Transmission Owner providing the generator interconnection should be required to perform the tasks as mentioned in R2, not the other entity (generator) even though it is registered as the Transmission Owner. 3) R2 2.1 performs a short circuit study to determine the present fault current values, not less than once every 24 months. 24 months is too often. Suggest to change to "once every 60 months unless there is major equipment change on the system".
Response: Thank you for your comment. **1. Based on comments, the drafting team has changed the Application, 4.2 Facilities to "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements."** **2. The drafting team added the following to the Rationale for R2, "(This requirement does not apply to the subject Generator Owner if it is also registered as a Transmission Owner, unless also registered as a Transmission Owner interconnecting to its own generator)" to address your comment.** **3. The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2.**		
Xcel Energy		1) It appears that clarification is needed in the Application guidelines with respect to the Generator Owners, Distribution Providers and Transmission Owners. If they are the same corporate entity, do the examples indicate as such and would coordination be required as specified? (It is presumed YES but not clear...e.g. GO

Organization	Yes or No	Question 9 Comment
		"R" and TO "S" could be the same corporate entity). Figure 5 implies the letters "R", "S", and "T" refers to different corporate entities since there is a Transmission Owner R and a Transmission Owner S along with a Generator Owner T. If these letters do not indicate different corporate entities, then is it the intention of the SDT that all GO and DP facilities that connect directly to the BES be treated as "Interconnected Facilities"?. 2) Additional clarification in the Application Guide (figure 3) is required as it would imply that proof is require that generation on a tapped substation does not pose a risk to the transmission system. 3) The dates and documentation requirements for this standard will require an equivalently complex system or database for tracking in order to prove compliance. From review of the standard it appears that tracking of ~8 dates and associated supporting documents will be required for each interconnection study. Additional implementation time should be included in the standard for proper processes and tools to be in place prior to perform study or re-study work. 4) Most study work would be initiated by R3.2 and typically involve multiple data requests for varying items and with associated responses providing the information. If each email request needs a corresponding response, then much time will be required to match emails topic for topic to meet this measure. The result will be multiple of same measure for study work, increasing tracking time for engineering. (i.e. more tracking time and less engineering time per engineering FTE). If the measure is to be based on first request to last response then this would easier to implement. 5) As existing studies will fall under the measures of this document, with no grandfathering, it is likely existing studies will need to be re-evaluated. As a result, consulting services for competent protection engineering services may become limited and may impact the ability in meeting the 36 month requirement. 6) Larger regional studies with interconnection impacts may be the outcome of

Organization	Yes or No	Question 9 Comment
		more localized studies. Such studies could be recommended as a result of R2 of this document or future year models under R3.1. The time-frames specified in this standard may not be sufficient and no exception method is provided for expanded study work. (i.e.-studies beyond what is would be considered typical for an interconnection study).
Response: Thank you for your comment. 1. **The drafting team has removed the term Interconnected Facilities and replaced it with Interconnected Elements, which is defined as "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity." The drafting team believes that the definition includes a Generation Owner and Transmission Owner that are part of the same registration, but would exclude a single Transmission Owner that is responsible for all interconnected terminals.** 2. **Based on comments received, the drafting team has revised the description relating to Figure 3 in the "Guidelines and Technical Basis".** 3. **The drafting team believes that the proposed requirement time frames and effective date allow sufficient time to comply with the standard.** 4. **The drafting team did not change the standard based on this comment.** 5. **The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists"** 6. **Based on comments, the drafting team has modified requirement 4, Part 4.2 to state, "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element agree with any resulting Protection System(s) changes." The drafting team believes that regional studies as a result of Requirement 2 are outside the scope of this standard.**		
Pepco Holdings Inc. & Affiliates		1) The SDT states that "the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14,

Organization	Yes or No	Question 9 Comment
		2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address the appropriate use of time delays in relays". However, a word search of the 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. The mention of "the appropriate use of time delays in relays" in the 2003 Blackout Report was in the context of the actuating time of relays in response to system overload conditions, and generator protection to voltage and frequency excursions during stressed system conditions. The concern was that relays operated on overload before system operators could react and that some generators tripped (exacerbating the collapse) before other system schemes (UFLS or UVLS) could operate. The solution was not to increase the time delay on Zone 3 relays (which would have been intolerable for fault clearing purposes) but to address the relay loadability issue in PRC-023, to make them immune from operating under heavy load conditions. Similarly the premature tripping of generators on voltage and frequency protection during stressed system conditions (not fault conditions) and coordination with system UFLS and UVLS schemes was discussed in the report. Likewise those issues have now been addressed, or are being addressed, in PRC-006, PRC-010, PRC-022, PRC-019, and PRC-024. Similarly in the recent Southwest Blackout of 2011 the operation of relay schemes during overload conditions was a contributing factor. There was again no evidence of miscoordination of relay schemes during fault conditions. The unexpected operation of relays and SPS's during overload conditions could have been avoided by proper application of existing standards PRC-023 and PRC-014-0. Based on the above, where is the historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions? Reliability Standards should be adopted based on a need to address a known, or probable, reliability issue.

Organization	Yes or No	Question 9 Comment
		As such, although we support the overall desire to ensure that protective systems are "properly coordinated"; we see little value in developing a new Reliability Standard to address something that is routinely practiced and which has not been demonstrated to be a contributor to major system disturbances, or cascading outages. Even the SDT in their rationale for Requirement R1.1 stated that they have no evidence that there is widespread miscoordination between Interconnected Facilities. In lieu of a formal standard to address relay coordination during faults, a simple technical reference document on Protective System Coordination issues may provide equal benefit to the industry. 2) PRC-001 With the vast majority of the requirements from PRC-001-1 being removed, the Title and Purpose of proposed standard PRC-001-3 no longer seem appropriate for the content remaining therein and should be revised. The only remaining requirement in PRC-001-3 states that "Each Transmission Owner, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. This does not seem to be a Protection System Coordination issue. 3) The definition of Interconnected Facilities should reference Registered Entities rather than functional, operating, or corporate entities. BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities Registered Entities (TOs, GOs, and/or DPs). 4) Is Facility and/or Element the best term(s) to use in the definition? It seems to say Elements that are joined by Elements? If not, should the definition be further revised. NERC Glossary of terms for Element: Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components. NERC Glossary of terms for Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.) 5) Does joint own lines and stations create issues? Should the definition or standard

Organization	Yes or No	Question 9 Comment
		make a distinction between principal owner and financial owners?

Response: Thank you for your comment.

1. **PRC-027-1 is replacing Requirements R2 and R3 of PRC-001-2. The drafting team is developing this standard based on the Standards Committee approved SAR, and is addressing directives issued by FERC in Order 693.**
2. **This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff.**
3. **The drafting team has removed the term "Interconnected Facilities" and replaced it with "Interconnected Elements," which is defined as "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity."**
4. **The drafting team replaced the term "Interconnected Facilities" with "Interconnected Element."**
5. **The drafting team believes that the individual owners' Protection Systems are well defined, but if there is joint ownership in the Protection Systems, compliance responsibility has been delegated for other standards and this standard has a similar need for delegation of responsibility.**

Organization	Yes or No	Question 9 Comment
Northeast Power Coordinating Council		1. Referring to the Example Process on page 22, it should not be the responsibility of Entity B to propose revisions. It should be the responsibility of the Entity in the better position to propose a revision to propose the revision. There needs to be flexibility as to who is obliged to come up with a revision. 2. Regarding Fig. 2 and Fig. 5 in the Application Guidelines, it is important that the expertise of each entity involved in an interconnection be used to ensure that there are no coordination issues. For example, Generator Owners and Transmission Owners. 3. Application Guidelines Fig. 3 requires the TO to verify that the DP's and the GO's protection systems coordinate with the TO's, even though the GO doesn't connect directly to the TO. It should be the DP that checks coordination of the GO with the DP for faults on the transmission side of the DP's substation transformer, and the TO that checks coordination of the DP's transmission protection with the TO. If all of the transmission protection is back at the GO (in other words the DP has installed no

Organization	Yes or No	Question 9 Comment
		transmission protection at its sub) then to do as this app guide suggests the TO will require an accurate short circuit model of the DP's system between the GO and the TO. It would require that the DP keep the TO continuously appraised of changes to the DP's system that impact the short circuit representation. Considering the proliferation of distributed generation being interconnected to distribution systems the burden should be on the DP not on the TO supplying the DP to verify coordination. The scope of the text "....generator protection systems...." should be narrowed so a TO or DP is not responsible for the coordination of devices it doesn't own, maintain or set.
Response: Thank you for your comment. 1. **The drafting team believes that the Example Process does allow the flexibility that you describe. The collaboration would begin at the point where Entity B responds to Entity A with its proposal.** 2. **The drafting team believes that there is flexibility in the process to allow for the expertise of each entity to be used to coordinate Protection Systems.** 3. **Based on comments received, the drafting team has revised the description relating to Figure 3 in the "Guidelines and Technical Basis" to clarify that only the Distribution Provider's Protection Systems installed to protect for Faults on Transmission System Elements are a part of the Applicability of this standard.**		
Independent Electricity System Operator		1. As a general comment, we do not support defining new terms which have limited applications (e.g. for use in one or very few standard) and which are short and therefore can be equally effectively expressed in the requirement that the term or its intended meaning is used. Adding new terms to the NERC Glossary when not absolutely necessary creates unnecessary maintenance workload and dependency among standards that use the same term, making it far more difficult to revise a standard without addressing the ripple effects. While we do not oppose to defining the term Interconnected Facilities as it serves to clarify and provide the boundary of the Facility, and we see its potential application to other standards, we disagree with defining the term "Protection System Study". The definition contains an objective "operate in the

Organization	Yes or No	Question 9 Comment
		desired sequence for clearing Faults" that should be stipulated in the standard requirements themselves. Further, as suggested below, the requirements that this term is used can be easily revised to convey the meaning of the definition: R1, 1.1 Perform a study for each Interconnected Facility to verify that Protection Systems operate in the desired sequence for clearing Faults and remove from service only those Elements required to isolate Faults as follows:1.1.1 Within 36 calendar months after the effective date of this standard, if no such study for that Interconnected Facility exists that was performed on or subsequent to June 18, 2007R1, 1.2 Provide to each affected Interconnected Facility owner a summary of the results of each study performed pursuant to Part 1.1 of this requirement, (including, at a minimum, the Protection System(s) reviewed, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each study.R2, 2.2 Calculate the percent deviation between the Fault current values (single line to ground and 3-phase for the bus(s) or Element(s) under consideration) used in the most recent study performed under Part 1.1 of R1 and the Fault current values....Vpss = Fault current value used in the most recent studyR4, 4.1 Within 90 calendar days after receipt, confirm agreement with the summary results of a study as described in Requirement R1, Part 1.2.Conforming changes can be made to the associated Measures and VSLs. 2. We do not agree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. If this is a training requirement, it should be transferred to the appropriate PER standards. c. Measures M1 is removed from the standard. This does not conform with the Elements of a Reliability Standard template, specifically those specified in the

Organization	Yes or No	Question 9 Comment
		"Mandatory and Enforceable Sections of a Standard". d. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. However, leaving this not measurable and unnecessary requirement in PRC-001-3 is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT could have proposed a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee's advice/direction for appropriate actions. 3. The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after "where such explicit approval is required" in the Effective Dates Section on P. 2, to the following effect:", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities."

Response: Thank you for your comment.

1. **The drafting team believes that defining the term "Protection System Study" is the most efficient way to refer to the necessary reviews and the best way to allow for description of the studies.**
2. **This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff.**
3. **The drafting team believes that the "Effective Dates" language used in the standard and in the Implementation Plan is appropriate and consistent with other reliability standards.**

Organization	Yes or No	Question 9 Comment
Southern Company		1. The separation of PRC-001-1 in three directions is appreciated. This move was a move in the right direction in our opinion. 2. Whereas the SPCTF may believe that the existing PRC-001-1 was too vague and was not measureable, we believe that the initial draft of PRC-027-1 is overly specificative. Contained within the four listed requirements are actually 11 requirements with 11 different time critical counters that are not to be violated. It is our opinion that equally effective reliability improvement results can be achieved with a standard that is of the form of something in between these two extremes. We propose to eliminate the multiple calendar based time framed requirements and simplify the eleven requirements into four simply stated requirements. The four requirements, simply, could be: 1) For each Interconnect Facility (IF), perform a Protection System coordination study/review every X years or sooner if triggered by Y. (Y = available fault current change % [r-iii below], system configuration change or other protection system change [r-ii below]); 2) IF owners must notify other IF owners of changes that may affect the other IF owner's Protection System coordination study. (list items likely to affect coordination-this list includes everything in the draft standard R3); 3) TOs are to notify other IF owners if available fault current changes significantly %; 4) IF owners must share & acknowledge receipt and review of their IF Protection System coordination study with other IF owners of that IF. 3. On figure 5 (p. 27 of the draft standard), it seems unreasonable to require that the GO coordinate their protection with that associated for breakers E, F, and G, which are three breakers away from the generator.

Organization	Yes or No	Question 9 Comment
		4. There is an error on p 5 of the Technical Justification document under Requirement R3. In the first sentence, it is R1, not R3, that requires the IF owners to evaluate the impact to their Protection Systems due to proposed changes by others.
Response: Thank you for your comment. **1. The drafting team thanks you for your support.** **2. The drafting team understands your concerns but believes that the requirements and associated time frames are the best way to ensure that Protection System coordination is achieved in a non-discriminatory fashion.** **3. The drafting team believes that the Generator Owner may have overreaching elements that require coordination with breakers E, F, and G and thus made no changes to the standard based on this comment.** **4. Based on your comment the drafting team modified the sentence to "This requires the registered functional entity initiating any change to provide the details to the other affected entities of the Interconnected Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes."**		
Hydro One		1. This standard has been written on the basis that one of the Entities initiates the process and that both, assuming 2 only, conduct their own independent Protection System Studies; and then at the end of the process they agree, etc. Based on our experience, it is more efficient that both parties work in cooperation to conduct the Protection System Study and that they produce one report document which is then approved by both entities as meeting adequate coordination requirements. The Protection System Studies report shall be dated, and include the fault values at the time of assessment and should be filed as compliance evidence. 2. The SDT states "The SDT has no evidence there is widespread miscoordination between Interconnected Facilities...." This is contrary to the NERC TRD that indicated that there were plenty of co-ordination issues during the 2003 Blackout. Suggest removing this statement as it is contradictory and serves no purpose since the documented Protection System study has to take place regardless. 3. We feel the standard would be more useful to the industry if a list of applicable

Organization	Yes or No	Question 9 Comment
		Protection System elements that require co-ordination is presented in the requirements section in line with the NERC white paper. Much like PRC-023 that identifies specific elements and corresponding numbers, we feel this approach would result in proper Protection System studies being undertaken for elements that are affected by this standard. The SDT claims some elements will be covered in other standards so the scope of elements that need co-ordination needs some clarity. 4. PRC-001-3 lists “first day of the first calendar quarter twelve months following” as the Effective Date. However, the implementation plan states that the effective date is the same as for PRC-027-1 which is “first day of the first calendar quarter that is three months beyond”. Please clarify and ensure consistency. 5. Hydro One is questioning the purpose and existence of PRC-001-3 in its current form. It contains only one requirement that is very vague and not measurable. Suggest that the SDT retires that standard as a part of this project 6. To avoid confusion we ask the SDT to establish 1 to 1 correspondence between the requirements and measure. For example R2 measures should be M2 or M2.1, M2.2 rather than M3 and M4.

Response: Thank you for your comment.

1. **The drafting believes that the standard does not preclude collaboration between the affected entities when performing the Protection System Study.**
2. **The drafting team believes that the coordination issues addressed in the 2003 Blackout report were related to UFLS, UVLS, and generator controls. While there were statements of general philosophy about the need for coordination of transmission line protection, there were no examples of miscoordination. As such, the drafting team has declined to remove the suggested statement from the standard.**
3. **Based on comments, the drafting team modified the Facility Applicability 4.2 to “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements,” which the team believes clarifies those Protection System Elements that are required to be coordinated under this standard.**
4. **The drafting team has modified the effective dates so they will be consistent. The effective date for PRC-001-3 is now**

Organization	Yes or No	Question 9 Comment
described as "This standard becomes effective coincidently with PRC-027-1." **5. The retirement of PRC-001-3 is beyond the scope of this drafting team; however, your comment will be forwarded to NERC staff.** **6. The drafting team followed the format outlined in the NERC "Standard Processes Manual," effective January 31, 2012.**		
National Grid USA / Niagara Mohawk		1. Regarding the definition of "Interconnected Facilities," when the functional and operating entities are part of the same corporate entity documented correspondence within that same corporate entity seems of little benefit. In fact, it could be the same individual wearing two hats in the same corporate entity who would have to document communications with him/herself. 2. Example process on page 22 should not automatically make it the responsibility of entity B to propose a solution to a problem discovered by entity A quite possibly resulting from system modifications initiated by entity A. Whether entity A or entity B is in a better position to propose a solution depends entirely on the circumstance and there needs to be flexibility as to who is obliged to come up with a fix. 3. Application Guidelines, Fig. 2 and Fig. 5 require the TO to verify "...the generator Protection Systems..." coordinate with the TO's systems. The scope of generator protection systems should be narrowed to just distance relays and overcurrent relays that look out onto the TO's system. If the high side winding of the transformer that interconnects to the TO is ungrounded and zero sequence overvoltage protection is provided for the transmission, then that would be appropriate to include in the scope of TO responsibilities too. The expertise in other types of generator protection likely resides with the GO and not the TO so it would be best if the GO handled the coordination of those other types of protection. 4. Application Guidelines, Fig. 3 requires the TO to verify the DP's and the GO's protection systems coordinate with the TO's. Yet the GO doesn't even connect directly to the TO. It should be the DO that checks coordination of the GO with

Organization	Yes or No	Question 9 Comment
		the DP for faults on the transmission side of the DP's substation transformer (assuming the DP has installed transmission protection at the sub) and the TO that checks coordination of the DP's transmission protection with the TO. If all of the transmission protection is back at the GO (in other words the DP has installed no transmission protection at its sub) then to do as this app guide suggests the TO will require an accurate short circuit model of the DP's system between the GO and the TO. Furthermore it would require that the DP keep the TO continuously appraised of changes to the DP's system that impact the short circuit representation. Considering the proliferation of distributed generation being interconnected to distribution systems the burden should be on the DP not on the TO supplying the DP to verify coordination of what could be a multitude of interconnections to the DP. Furthermore, the scope of the text "....generator protection systems...." should be narrowed so a TO or DP is not responsible for the coordination of devices it doesn't even own, maintain or set. When study work is required to interconnect a GO to an entity, the entity is commonly reimbursed by the GO for study work. Yet this app guide requires a TO to perform study work for the benefit of a GO which does not even directly interconnect with it so how will the TO be reimbursed for it's efforts?

Response: Thank you for your comment.

1. **The drafting team has removed the term Interconnected Facilities and replaced it with Interconnected Elements, which is defined as "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity." The drafting team believes that the definition includes a Generation Owner and Transmission Owner that are part of the same registration, but would exclude a single Transmission Owner that is responsible for all interconnected terminals.**
2. **The drafting team believes that the Example Process does allow the flexibility that you describe. The collaboration would begin at the point where Entity B responds to Entity A with its proposal.**
3. **The drafting team believes that there is flexibility in the process to allow for the expertise of each entity to be used to coordinate Protection Systems.**

Organization	Yes or No	Question 9 Comment
4. Based on comments received, the drafting team has revised the description relating to Figure 3 in the "Guidelines and Technical Basis" to clarify that only the Distribution Provider's Protection Systems installed to protect for Faults on Transmission System Elements are a part of the Applicability of this standard.		
Tennessee Valley Authority		a)Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1, Part 1.1.2 reads - "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required." For Requirement R1, Part 1.1.2, we recommend omitting the reference to R2 and reword so that the requirement is specific. Recommend changing to read: "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required". b) The standard uses different formats for identifying deadlines. Sometimes "days" are used and sometime "months" are used. It is suggested that a common format be used. c) Please note that there appears to be an inconsistency in the 24 month requirement of R 2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual Requirements where time schedules are involved, the wording of the Requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the

Organization	Yes or No	Question 9 Comment
		time schedule at the beginning of the Requirement whereas R1-1.2 references the time schedule at the end of the Requirement. Recommend using a standard wording format and list the time horizons in the beginning of the Requirement in all Requirements that have time requirements involved. For Requirement R1-1.2, we recommend changing to read: "Within 90 calendar days after the completion of the Protection System Study: Provide, to each affected Interconnected Facility owner, a summary of the results of each Protection System Study performed (including at a minimum the Protection System(s) reviewed and any proposed revisions)." e) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. i) The overall process would be less burdensome by changing R2, Part 2.1 to "not less than once every 5 calendar years" which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3. ii) The overall process would be less burdensome by deleting R3, Part 3.3 because such Protection System changes are already captured by R3, Parts 3.1 and 3.2. iii) Omitting 'project schedule' from R3 would streamline data exchange. f) Delete 'operating' from the Interconnected Facilities definition because "different functional or corporate entities" sufficiently captures all of them. We also suggest defining the singular Interconnection Facility, rather than the plural.

Response: Thank you for your comment.

a. **The drafting team believes that your proposal does not change the requirement and the reference to the other requirements in this standard is the best way to both maintain consistency and to describe the requirements. The team declined to make the suggested changes.**

Organization	Yes or No	Question 9 Comment
b. The drafting team chose to use "months" for any measurable period longer than 90 calendar days and believes this does not introduce any problem with meeting the requirements. c. The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require. d. The drafting team believes that references to the time horizons are accurately and sufficiently described and declined to make the suggested changes. e. i) The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require. ii) Based on comments, the drafting team combined Requirement 3, Parts 3.3.1 and 3.3.2 into Part 3.3. However, the drafting team notes that the triggers for Requirement R3, Part 3.3 are different than those for Requirement R3, Parts 3.1 or 3.2 and therefore declines to delete Requirement R3, Part 3.3. iii) The drafting team believes that omitting the "project schedule" from the list of example data submittal will not streamline the data exchange, but the schedule is very likely required to ensure that each entity can allocate resources as necessary. f. Based on comments, the drafting team changed Interconnected Facilities to Interconnected Elements defined as follows, Interconnected Elements: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.		
SERC Protection and Control Subcommittee		a)Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another

Organization	Yes or No	Question 9 Comment
		Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1-1.1.2 reads - “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.” For Requirement R1-1.1.2, recommend omitting the reference to R2 and reword so that the requirement is specific. Recommend changing to read: “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required”. b) The standard uses different formats for identifying deadlines. Sometimes “days” are used and sometime “months” are used. It is suggested that a common format be used. c) Please note that there appears to be an inconsistency in the 24 month requirement of R2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1, which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual requirements where time schedules are involved, the wording of the requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the time schedule at the beginning of the requirement whereas R1-1.2 references the time schedule at t the end of the requirement. Recommend using a standard wording format and list the time horizons in the beginning of the requirement in all requirements that have time requirements involved. For Requirement R1-1.2, recommend changing to read: “Within 90 calendar days after the completion of the Protection System Study, provide to each affected Interconnected Facility owner a summary of the results of each Protection System Study performed (including at a

Organization	Yes or No	Question 9 Comment
		minimum the Protection System(s) reviewed and any proposed revisions).” e) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. i) The overall process would be less burdensome by changing the R2 2.1 to “not less than once every 5 calendar years” which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above).Our experience is that the vast majority of Protection System Studies are triggered by R3. ii) The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. iii) Omitting “project schedule” from R3 would streamline data exchange. f) Delete “operating” from the Interconnected Facilities definition because different functional or corporate entities sufficiently capture all of them. We also suggest defining the singular Interconnection Facility, rather than the plural.”The comments expressed herein represent a consensus of the views of the above named members of the Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”

Response: Thank you for your comment.

a. **The drafting team believes the reference to the other requirements in this standard is the best way to both maintain consistency and to describe the requirements. The team declined to make the suggested changes.**

b. **The drafting team chose to use “months” for any measurable period longer than 90 calendar days and believes this does not introduce any problem with meeting the requirements.**

c. **The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually**

Organization	Yes or No	Question 9 Comment
(Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require. d. The drafting team believes that references to the time horizons are accurately and sufficiently described and declined to make the suggested changes. e. i) The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require. ii) Based on comments, the drafting team combined Requirement 3, Parts 3.3.1 and 3.3.2 into Part 3.3. However, the drafting team notes that the triggers for Requirement R3, Part 3.3 are different than those for Requirement R3, Parts 3.1 or 3.2 and therefore declines to delete Requirement R3, Part 3.3. iii) The drafting team believes that omitting the “project schedule” from the list of example data submittal will not streamline the data exchange, but the schedule is very likely required to ensure that each entity can allocate resources as necessary. f. Based on comments, the drafting team changed Interconnected Facilities to Interconnected Elements defined as follows, Interconnected Elements: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.		
Operational Compliance		All of the questions in this survey should elicit a "yes" response to agree with the Standard. Question 2 elicited a "no" response even though we agree with the part of the standard in the question. The questions in this survey should be worded to ask if we agree with the exact wording of the standard. For example, in Question 4 the wording of the question is different than in the Standard regarding deviation.
Response: Thank you for your comment. The drafting team agrees.		

Organization	Yes or No	Question 9 Comment
City of Austin dba Austin Energy		Austin Energy (AE) agrees with PRC-027-1 in concept and is prepared to change our vote to affirmative once the SDT addresses the items in these comments. In addition to those provided as part of the specific questions, AE provides the following comments for consideration: (1) AE requests the SDT to identify a timeframe for R1.1.3. The Guidelines and Technical Basis (p17 of PRC-027-1 Draft #1) states, "The SDT believes that specifying a single time frame for evaluation of the wide variety of conditions that may be associated with a particular change is not appropriate ..." The flowchart on page 21 shows a system change that triggers the need for a new study leading to a box that requires the study be performed within six months. Please remove the conflicting information. (2) AE supports a timeframe that requires a Protection System Study in accordance with a mutually agreed-upon schedule that includes confirmation of agreement with summary results (per R4.1) prior to the in-service date of any planned change. AE suggests the SDT identify this timeframe in R1.1.3 and delete R4.2. (3) AE requests that the SDT change the values in the % Deviation formula (R2.2) from VSCS and VPSS to ISCS and IPSS since V is typically used for voltage. AE also requests the SDT change the variable definitions from "fault current value ..." to "fault current magnitude ..." to clarify that the phase angle is not included.

Response: Thank you for your comment.

1. **The drafting team has modified the flowchart based on comments and to reflect all changes made to the standard.**
2. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**
3. **Based on comments, the drafting team has modified the equation to replace "V" with "I." The drafting team kept the phasor values of the current in the calculation but included the percent deviation to be the absolute value of the percentage change**

Organization	Yes or No	Question 9 Comment
in the current to remove the angle from the final result.		
Oncor Electric Delivery Company LLC		Based on a thorough review of the proposed Standard, Oncor has identified several questions or comments which need to be addressed in the Standard to ensure the Requirements are clear. 1. R4.1: please provide clarification of which entity would be out of compliance if the 90 day requirement is not met - initiating entity or receiving entity or both 2. M9: What does "confirmation" mean as explained in Measure M9? 3. R4: please incorporate a definition of “agreement” 4. R4.2: please incorporate some examples for "evidence of agreement"? 5. There are two types of agreement that are needed; the first being an "agreement" with the overall projected relaying scheme (i.e. agreement with preliminary conceptual design detailing proposed protection scheme changes). This is prior to any equipment being purchased. The second agreement, which could be identified as more of a concurrence, is agreement that both relay systems coordinate from a protection standpoint (i.e. concurrence with relay setting changes). The relay setting process and concurrences occur later in the project closer to the in-service dates. In addition, the sub requirements 4.3.1 and 4.3.2 calls for confirmation of the Protection System changes are acceptable pursuant to notification received in Requirement 3, within 30 days, however the sub requirements provide no mechanism for resolution in the event the changes are not acceptable to the receiving entity within 30 days of receipt. Oncor suggest that these two sub requirements be removed. There are sufficient checks and balances under 4.2 to provide coverage for any disagreement between entities without the need to self-report under the 4.3.1 and 4.3.2 if an agreement cannot be reached within 30 days of receipt.

Organization	Yes or No	Question 9 Comment
		6. R3.1: please provide further clarification of the statement "modifies the conditions used". It would seem that most system changes would modify the conditions used even though for many of those changes, coordination would not be impacted. Oncor takes the position that the phrase provides ambiguity and subjectivity that would difficult to measure or audit.

Response: Thank you for your comment.

1. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes..**
2. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Measure M9 was revised to read: "Acceptable evidence for Requirement R4, Part 4.1 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement."**
3. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Acceptable evidence for R4, Part 4.1 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement"**
4. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm that the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."Acceptable evidence for R4, Part 4.1 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement."**
5. **Based on comments, Requirement 4, Part 4.3 was removed.**
6. **Based on comments, the drafting team clarified the items in Requirement 3, Part 3.1 to indicate which items the drafting team**

Organization	Yes or No	Question 9 Comment
believes modify the conditions used in the coordination of Protection Systems.		
Luminant		Comment on Requirement R1.2. The time frame listed may not be adequate under all circumstances or situations. Luminant recommends that the language be changed in this requirement as follows: "... Protection System Study performed pursuant to this requirement (including at a minimum, the Protection System(s) reviewed, any issued identified, and any revisions proposed) shall be in accordance to an agreed-upon schedule with a Transmission Owner, Generation Owner, of Distribution Provider." The corresponding measures will also need to be modified if this language is accepted.
Response: Thank you for your comment. **The drafting team believes that 90 days is adequate time to provide the owner(s) of the Protection System(s) associated with the Interconnected Element(s) with the summary of the results of a Protection System Study and declined to change the standard based on this comment.**		
Trans Bay Cable		Comments: The comment group agrees with the WECC Position Paper that the standard as written requires excessive and burdensome documentation that is not needed to demonstrate coordination.
Response: Thank you for your comment. **The drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.**		
Dominion		a). Dominion is concerned that a YES vote will also endorse the revision, also part of this project, to PRC-001-3, would then be reduced to only one requirement that is not measurable and does not contribute to the purpose of the standard. The Measure for the requirement has also been removed. The PRC-001 standard should be retired or mapped to another standard.

Organization	Yes or No	Question 9 Comment
		b). The proposed definition of Protection System Study is vague and introduces subjective terms such as "demonstrates" and "desired sequences". Recommend the following definition: "A study that determines the proper selection of settings for existing or proposed protective relays in order to properly isolate Elements." c). Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1-1.1.2 reads - **"Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required."** For Requirement R1-1.1.2 - Omit the reference to R2 and reword so that the requirement is specific. Recommend changing to read: "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required". - Change R1-1.1.3 wording to read "When proposing or being notified of a change that modifies the conditions used in the coordination of Protection Systems at the Interconnected Facility unless the entity can demonstrate such a study is not required." - R2-2.2, delete reference to R2. Delete "pursuant to Requirement R2, 2.1". - Change R4-4.1 to read: "Within 90 calendar days of receiving summary results of a new Protection System Study, confirm agreement with the summary results." - Change R4-4.2 to read: "Prior to the installation of a proposed change that

Organization	Yes or No	Question 9 Comment
		modifies the existing conditions used in the coordination of Protection Systems of the Interconnected Facilities, confirm the affected Interconnected Facility owner(s) agree with the Protection System(s) change." - Change R4-4.3.1 to read: "Changes made to a Protection System as a result of findings during Misoperation investigations, commissioning, or maintenance activities, confirm the Protection System(s) changes are acceptable." - Change R4-4.3.2 to read: "Emergency replacements are made due to failures of Protection System components confirm the Protection System(s) changes are acceptable." d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual Requirements where time schedules are involved, the wording of the Requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the time schedule at the beginning of the Requirement whereas R1-1.2 references the time schedule at the end of the Requirement. Recommend using a standard wording format and list the time horizons in the beginning of the Requirement in all Requirements that have time requirements involved. For Requirement R1-1.2, Change wording to read: **"Within 90 calendar days after the completion of the Protection System Study, provide to each affected Interconnected Facility owner a summary of the results of each Protection System Study performed (including at a minimum the Protection System(s) reviewed and any proposed revisions)."** - Change R2- 2.3 wording to read: Within 30 calendar days after identifying that the calculation performed between the previous Protection System Study and the new study indicates a change in Fault current of 10% or greater, notify each Interconnected Facility owner, at which the 10% or greater change applies.

Organization	Yes or No	Question 9 Comment
		- Chang R3-3.2 wording to read: <u>"Within 30 calendar days of receiving a request for information in the absence of an agreed-upon schedule or according to an agreed-upon schedule with a Transmission Owner, Generator Owner, or Distribution Provider."</u> e). Throughout this 1st draft of the standard, there are references that illustrate documentation requirements that are inconsistent. <u>Recommend all be written as "(hard copy or electronic file formats)".</u> f). Please note that there appears to be an inconsistency in the 24 month requirement of R 2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. g). There are several requirements stipulated throughout the draft standard creating the concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. 1). The overall process would be less burdensome by changing the R2 2.1 to "not less than once every 5 calendar years" which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3. 2). The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. 3). Omitting 'project schedule' from R3 would streamline data exchange. h). There is confusion on the connections at the end of the flow chart. Please provide clarification.

Organization	Yes or No	Question 9 Comment

Response: Thank you for your comment.

a. **The retirement of PRC-001-3 is beyond the scope of this drafting team; however, your comment will be forwarded to NERC staff.**

b. **The drafting team declines to modify the definition of the Protection System Study but did add the following to the description in the "Guidelines and Technical Basis": "System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions." The drafting team believes that the full description in the Guidelines and Technical Basis is now adequate and appropriate.**

c. **The drafting team believes the reference to the other requirements in this standard is the best way to both maintain consistency and to describe the requirements. The team declined to make the suggested changes.**

d. **The drafting team believes that references to the time frames are sufficient and declined to make the suggested changes.**

e. **The drafting team does not agree that the references "illustrate documentation requirements that are inconsistent." Each measurement in the standard (M1 through M10) has as evidence the statement "dated documentation (hardcopy or electronic file formats)."**

f. **The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require.**

g. **1) The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard**

Organization	Yes or No	Question 9 Comment
does not require. 2) Requirement R3, Part 3.3 was not in the version of the standard that was sent out for comment. Based on consideration of comments the subparts (R3.31 & R3.3.2) have been combined as Requirement R3 Part 3.3. 3) The drafting team believes that omitting the "project schedule" from the list of example data submittal will not streamline the data exchange, but the schedule is very likely required to ensure that each entity can allocate resources as necessary. h. The drafting team has modified the flowchart based on comments and to reflect all changes made to the standard.		
Idaho Power Company		1. During our review it appears that an Entity will need to maintain an exceedingly large list of contacts for all Interconnected Facilities in order to ensure that the appropriate personnel receive and respond appropriately to Protection System coordination requests as Required by this Standard. With the probability of regular turnover occurring (retirements, transfers, etc.) at Interconnected Facilities, it would be helpful for a master list of Interconnected Facility Contacts for Protection Systems be held by a centralized Entity, such as a Reliability Coordinator, in order for an Entity to meet the timeframes specified and facilitate reliability via compliance with this Standard. 2. This Standard will enforce consistent communication between Entities which is necessary for coordination of Protection Systems. It does not however, guide an Entity to set relays that will ensure proper coordination. Having a separate Entity verify coordination is desirable, but differences in experience, expertise, and analysis tools between Entities will not ensure proper coordination if methods of checking are not also part of the Requirements.
Response: Thank you for your comment. 1. Your comments concerning the need for a current listing of "Interconnected Facility Contacts" is very perceptive, but cannot be addressed by the Requirements of the standard. The drafting team believes that ultimately it is the owner's responsibility		

Organization	Yes or No	Question 9 Comment
to maintain this list; however, if you can reach an agreement with the Reliability Coordinator, that may be option. **2. The drafting team agrees with your comment that the "Standard will enforce consistent communication between Entities which is necessary for coordination of Protection Systems" but disagrees with your assertion that "Entities will not ensure proper coordination if methods of checking are not also part of the requirements." The drafting team believes that all interconnected Protection System Owners have the capability of self checking their setting that will ensure coordination without making external checking of Protection Studies a Requirement of this standard.**		
FirstEnergy		FE offers the following additional comments: a. PRC-001-2 R1 - This requirement is vague and causes difficulties in consistent interpretations between entities and auditors. We ask the drafting team to revise the wording to clarify the expectations, such as including the types of protections system limitations they should be aware of. Enhancements to this requirement were also suggested in the "NERC SPCTF Assessment of Standard PRC-001-0 - System Protection Coordination" which is attached to the SAR of this project. In their assessment of R1 of PRC-001, the SPCTF said "This requirement is a statement of a highly laudable goal, but this is not specific and enforceable. .. It may be possible to restate this requirement in such a way to be measurable and enforceable. The protective system equipment owners (Transmission Owners, Generator Owners, and Distribution Providers) should be responsible to provide the necessary information to the Transmission Operator and Generator Operator to facilitate their familiarity with the relevant protective systems." We ask the SDT to review this assessment and make changes to PRC-001 and PRC-027 to assure the reliability goal of PRC-001 R1 is met. b. With the approval of PRC-027-1, Requirements R3 and R4 will be retired from PRC-001-1 (Requirements R2 & R3 from PRC-001-2, approved as part of the Real-time Operations Project 2007-03) PRC-001-3 will have the same effective date as PRC-027-1. However, in the redlined version of PRC-001-3, the effective date is designated as "the first day of the calendar quarter twelve months following applicable regulatory approval". This is not what is specified in the

Organization	Yes or No	Question 9 Comment
		Implementation Plan.
Response: Thank you for your comment. a. **The drafting team believes that Requirement R1 falls outside the scope of Project 2007-06 and should remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard.** b. **The drafting team has modified the effective dates so they will be consistent. The effective date for PRC-001-3 is now described as "This standard becomes effective coincidently with PRC-027-1."**		
LCRA Transmission Services Corporation		General Comment: First, as industry comments are considered by the SDT, the standard must continue to take into consideration that the fundamental objective of a protection system is to prevent equipment damage that may occur as a result of a short circuit by ensuring fault isolation. The secondary objective is to maintain the power delivery capability in the rest of the system during a fault. This must not be compromised. Second, setting of protective relays is an art and finding a balance between dependability and security is already a challenge and may be an area of disagreement amongst owners (in some cases entities may end up "agreeing to disagree"). The standard should not take away the protection system owner's responsibility and right to set its own protection systems by requiring "Approval" from other interconnection entities at the Interconnected Facility. Specific Comments: Title of the proposed standard- The title for this standard is misleading since it only applies to locations that contain Interconnected Facilities. LCRA TSC suggests changing the title to "Protection System Coordination for Interconnection Facilities" Terms-Protection System Coordination Study: A study that demonstrates existing or proposed Protection Systems maintain proper selectivity while clearing Faults.
Response: Thank you for your comment.		

Organization	Yes or No	Question 9 Comment
The drafting team agrees that two objectives of a Protection System are to "prevent equipment damage due to faults" and to "maintain the power delivery capability in the rest of the system during a fault." **Based on comments concerning agreement, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."** **The drafting team does not believe the standard title is misleading and therefore did not adopt your recommended title.** **The drafting team does not agree with expanding Protection System Study to "Protection System Coordination Study. Also the drafting team does not agree that "maintain proper selectivity while clearing Faults" adds significant clarity to the current definition of a Protection System Study.**		
Western Area Power Administration		General: Western disagrees with NERC standards becoming too specific on technical issues such as protective relay coordination. Protection Engineers are highly skilled and trained in system coordination and should be left to determine the proper course of action without the hindrance of PRC-027-1 requirements. There is a reason why, historically, protection system coordination has been termed "the Art and Science of Protective Relaying." The proposed standard also mentions that "Protection Systems remove from service only those Elements required to isolate Faults..." This statement can be problematic since backup functions such as remote Zone 3 distance elements cannot be overlapped reliably yet are necessary for N-2 and beyond contingencies. Also, in some case it may be desirable to allow for intentional overlap or mis-coordination depending on the circumstances. These issues need to be resolved in the proposed standard or the standard eliminated. Specific issues: a. We have concerns over what NERC considers to be a "Protection System Study". Needs clearer definition. - Swap requirement positions R1 and R3. I.e. make R1 be R3 and R3 be R1.

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		b. R2.2: Provide equation. And, use “I” instead of “V” when referring to current. c. R2.2: What values are being referred to for deviation calculation? (i.e. ground current, phase current, positive sequence, etc.) d. R2.2: Clarify the fault current contribution or provide a table specifying the details e. R3.1: Last bullet, suggest making the statement “Replacement of the transformer(s)” to cover all transformers. f. R3.2: How does the neighboring entity know when to request? g. R3: What are the details to be provided? Should only be for significant changes. h. Concerned about dates and timelines associated with this standard. Often schedules and tasks change during design, checkout and commissioning. R1.1.3 and R3 need to be clarified. i. Western believes that this standard will create more questions than it answers. The standard, as written, is not clear or concise and would surely lead to CAN's and FAQ's.

Response: Thank you for your comment

a. **The drafting team believes that the definition of Protection System Study, “A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults” is understandable and succinct and does not need to be more clearly defined. Also the drafting team does not believe that Requirements R1 and R3 need to be swapped.**

b. **Per your suggestion and others, the drafting team has modified the equation to replace “V” with “I”.**

c. **The standard has been changed to refer to “Single line to ground and 3-phase for the interconnecting bus(s) under consideration” for the “deviation calculation.”**

d. **Based on comments the fault current contribution in Requirement R2, Part 2.2 has been clarified to be “for the interconnecting bus(s) under consideration.”**

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e. Other transformers are included in the second bullet which is now a combination of the previous version's second and third bullets. f. In R3 Part 3.2 the "neighboring entity" can request information related to the coordination of Protection Systems of an Interconnected Element whenever it desires the information. g. The details to be provided for R3 Part R3.1, Part 3.2, and Part 3.3 of the standard are discussed in their respective parts and the Application Guidelines of the standard. However, the individual circumstance may dictate additional details that are required for a relay coordination study. h. The standard takes into account "schedules and tasks" changing "during design" by not establishing "dates and timelines" for Requirement R 3 Part 3.1. The drafting team believes that Requirement R3 and Requirement R1, Part 1.1. 3 have sufficient clarity in the respective standard Requirements and the Application Guidelines associated with the Requirements. i. The posting of the standard is intended to provide the opportunity for the drafting team to address industry comments and provide clarifications to the industry which will hopefully eliminate the need for CANs and FAQs.		
Southern Minnesota Municipal Power Agency		I agree with and support the comments of the MRO's NERC Standards Review Forum (NSRF).
Response: Thank you for your comment. **Please see the response to MRO's NERC Standards Review Forum (NSRF)**		
Illinois Municipal Electric Agency		IMEA recommends language be included in 4.2 Facilities to clarify the standard does not apply to a DP protective device that only detects a fault on a transmission element and does not trip an interrupting device that interrupts current supplied directly from the BES. To minimize misinterpretation and potential impact on small entity resources, it would strengthen the standard if Section 4.2 Applicability language specifies the standard does not apply to a DP that does not own a BES Element/Facility.
Response: Thank you for your comment. **The drafting team believes Distribution Providers that own "Protection Systems installed for the purpose of detecting Faults on**		

Organization	Yes or No	Question 9 Comment
Interconnected Elements of the BES and that require coordination for isolating those faulted Elements" should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners.		
American Transmission Company		1. In general, ATC agrees with the need to modify PRC-001. However, PRC-027 as written expands the scope of PRC-001 by including Distribution Providers (DP). 2. The SDT, on both page 6 and 16 states that there is "no evidence of widespread miscoordination between Interconnected Facilities..." They further state on page 16 that "Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperation." Based on the above statements, ATC questions the need for the level of prescription in the standard. 3. ATC asks the SDT to update the numbering for measures to match the requirement numbering. 4. Reliability Standard TPL-001-2, which has been approved by NERC BOT, requires short circuit analysis. ATC believes that PRC-027-R2.1 is duplicative.
Response: Thank you for your comment. **1. The drafting team believes Distribution Providers that own Protection Systems installed for the primary function of detecting Faults on BES Elements should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners. To add clarity to this issue, the drafting team revised Applicability Section 4.2 Facilities as follows: Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements. Additionally, the drafting team changed the term "Interconnected Facilities" to Interconnected "Elements" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity"** **2. The drafting team stands by the quoted statement that there is "no evidence of widespread miscoordination between Interconnected Elements." However, because communication of changes at the interconnection or changes that effect the**		

Organization	Yes or No	Question 9 Comment
Protection Systems at an Interconnected Element is required for proper coordination, the "level of prescription in the standard" is required. 3. The drafting team followed the format outlined in the NERC "Standard Processes Manual," effective January 31, 2012. 4. The drafting team believes that the referenced requirement in TPL-001-2 is related to interrupting capabilities and is not directly related to Protection System coordination. The reliability intent and purpose of the two standards is different and therefore they are not "duplicative".		
Southwest Power Pool NERC Reliability Standards Development Team		1. In R2 the 24 month time period needs to be changed to 60 months. If fault currents are already being calculated for changes to the system there should be little to no need for a more current check of the fault currents. We feel like the 24 months could be burdensome to smaller entities. 2. We would ask that PRC-001-3 be retired and the requirement in it to be moved to a SAR for an existing PER training standard. It also seems incomplete that a standard with a single requirement has no measures. 3. Is there a need for the defined term "Protection System Study" in this standard to also be a new term in the NERC glossary of terms? Is there other wording that could be used in place of this new term since it is only being used as part of this standard?
Response: Thank you for your comment. 1. The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. 2. This drafting team is not addressing the refinement of PRC-001-3. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard". 3. The drafting team believes that the definition of Protection System Study is needed but based on your comment the drafting team has specified that the new term will not be added to the NERC glossary of terms.		

Organization	Yes or No	Question 9 Comment
Bonneville Power Administration		Interconnections are no more prone to misoperations than other power system elements. A logical conclusion is that if the requirements of this standard are put in place for interconnected facilities, they should be put in place for all power system elements. The industry is quickly approaching a prescriptive environment in the protective relaying field which attempts to replace experience and judgment with a massive set of rules. These rules will never be able to eliminate miscoordination and misoperations, and the more rules we have, the more time and resources are diverted from dealing with the critical issues that arise. Entities are no longer free to use experience and judgment to decide what work is most important and instead, focus time and energy on the relentless schedule of NERC requirements. The purpose of the original System Protection Coordination Standard, PRC-001, was to ensure that protection systems were coordinated among entities. This should require only a simple exchange of data between entities when new facilities are added or changes are made. BPA implores the SDT to reduce the burden of the proposed standard by simplifying it and returning to the basic original purpose.
Response: Thank you for your comment. **The drafting team agrees that "Interconnections are no more prone to misoperations than other power system elements" and that the intent of the "original System Protection Coordination Standard, PRC-001, was to ensure that protection systems were coordinated among entities." The Purpose of PRC-027-1 "To coordinate Protection Systems for Interconnected Elements …." does not imply that the requirements of PRC-027-1, when put in place for interconnected elements, should be put in place for all power system elements. Because communication of changes at the interconnection or changes that effect the Protection Systems at an Interconnected Element is required for proper coordination, the level of prescription in PRC-027-1 is required. The drafting team believes that the coordination of other system elements that are owned by the same Transmission Owner, Generator Owner, or Distribution Provider are governed by their internal protection coordination quality control processes.**		
Tacoma Power		1. Is it the expectation of the SDT that Protection System coordination issues may be identified when Protection System Studies are performed pursuant to R1.1.1? 2. If such issues are identified, is it the intention of the SDT that these issues

Organization	Yes or No	Question 9 Comment
		would constitute violations of PRC-027-1, provided that the process described in PRC-027-1 for remedying these issues is followed? 3. Transmission Owners depend on each other for accurate short circuit models. As proposed, PRC-027-1 does not appear to clearly address sharing of short circuit modeling information among Transmission Owners when incremental changes are made within a Transmission Owner's system. For example, incremental changes in adjacent Transmission Owners' systems may result in a 5% change in Fault current at an Interconnected Facility when the changes are considered separately, but when the changes are considered together, the Fault current might change by 10%. While the +/- 10 % change in an Interconnected Facility's Fault current value as a trigger appears to be reasonable, the proposed standard offers no guidance or requirements concerning the accuracy of an entity's short circuit model or the methods used to determine Element impedances. This issue is most pronounced for zero-sequence impedance, and to a lesser extent negative-sequence impedance, since these parameters are used infrequently in system planning studies. It seems that some standardized approach for determining impedance parameters may need to be developed, whether in this standard or in another standard, provided that some latitude is afforded entities based upon sound engineering judgment. 4. In R2.2, why is it not sufficient to simply include the following in the parentheses: "single line to ground and 3-phase for the bus(s) under consideration"?" 5. The formulas in R2 use V for current. For clarity's sake, current should be denoted using the letter I." 6. Under R3.2, if all applicable entities agree to a schedule, was it the intention of the SDT that the agreed-upon schedule could be longer than 30 calendar days? 7. M8 requires that an entity have evidence that other entities received

Organization	Yes or No	Question 9 Comment
		information pursuant to R3.3.1 and R3.3.2. What if, despite due diligence, one or more entities do not acknowledge receipt? 8. Since notification pursuant to R3.3 is after the fact, to be compliant, an entity depends upon one or more other entities to acknowledge receipt, but there does not appear to be a regulatory requirement for them to acknowledge receipt in a timely manner, only a requirement to confirm that the changes are acceptable within 30 days of receipt pursuant to R4.3. Consequently, if Entity A notifies Entity B of changes pursuant to R3.3 in 15 calendar days, Entity B would have until 45 calendar days following the change to respond. However, by this time, Entity A might not have documentation that it met its requirements under R3.3. Another challenge with R3.3 and R4.3 is that the language seems to assume that both entities will agree to the changes. While this should usually be the case, there may be instances in which the entity receiving notice may not find the changes acceptable. 9. Additionally, the language in R4.3 may influence the entity receiving the notice to deem the changes as being acceptable, even if they are not, in order to meet the 30 calendar day timeframe. 10. Tacoma Power thanks the SDT for including Figure 4 in the Application Guidelines. 11. In Figure 5 of the Application Guidelines, why would it be necessary to check for coordination issues with Protection System settings associated with Breakers A, B, C, and D? Is this language intended to address reverse elements that are independent of communications systems? Is it intended to include bus differential, which would be the scheme commonly applied? Or, is there some other reason? 12. To what extent can this standard be enforced within a Transmission Owner's system? For example, in Figure 1 of the Application Guidelines, in addition to verifying that there are no coordination issues between Protection System

Organization	Yes or No	Question 9 Comment
		settings associated with Breaker A and, say, Breaker F, does the SDT intend that this standard could be construed to grant regulatory authority to audit that a Protection System Study was completed to verify that there are no coordination issues between Protection System settings associated with Breaker F and other breakers within Transmission Owner S's system? 13. While Protection System settings associated with Breakers A and F may be coordinated, Breaker F may not be coordinated with other Protection System settings within Transmission Owner S's system such that Protection System settings associated with Breaker A might also not be coordinated for some Faults within Transmission Owner S's system. It is believed that this type of situation should be rare and that the scope of this proposed standard should be limited to audit and enforcement of Protection Systems at the Interconnected Facilities, as depicted in Figures 1, 2, 3, and 5. Assume that there is documentation supporting coordination of Protection Systems at Interconnected Facilities. However, during a Fault, a Mis-operation occurs, and the cause of the Mis-operation is attributed to mis-coordination, despite good faith on the part of the entities to coordinate Protection Systems. Is it the intention of the SDT that this Mis-operation would be construed as a violation of PRC-027-1? For example, although they are generally addressed to some degree in Protection System Studies, but often implicitly through margins, factors of safety, etc., phenomena such as CT saturation or DC offset are not always directly analyzed in Protection System Studies and could lead to mis-coordination even if Protection System settings appear to be coordinated in documentation. 14. It is not clear what responsibility the TO has if it models a generator's short circuit capability incorrectly. 15. The proposed changes to PRC-001 (proposed version 3) are supported. 16. As a reminder to the SDT, Protection System design and application is part science and part art, and it may be difficult to thoroughly audit and enforce

Organization	Yes or No	Question 9 Comment
		the latter. Tacoma Power appreciates the opportunity to comment on the proposed standard and thanks you for your consideration of our comments.

Response: Thank you for your comment.

1. **The drafting team believes that coordination issues may be identified when Protection System Studies are performed pursuant to R1.1.1 and this is the basis for this requirement.**
2. **The drafting team believes that any coordination issues identified when Protection System Studies are performed pursuant to Requirement R1, Part R1.1.1, Part 1.1.2 or Part 1.1.3 are discovered would lead to corrective actions as identifies in the other requirements.**
3. **The drafting team believes that developing a standardized approach for determining impedance parameters is outside the scope of this project.**
4. **The drafting team believes the existing wording is appropriate and did not make your suggested change.**
5. **Per your suggestion and others, the drafting team has modified the equation to replace "V" with "I"**
6. **Under Requirement R3 Part 3.2, if all applicable entities agree to a schedule, the intention of the drafting team is that the agreed-upon schedule could be longer than 30 calendar days.**
7. **Measure M8 has been modified to indicate that information was provided within 30 days; therefore, an acknowledgement of receipt is no longer required.**
8. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**
9. **Based on comments, the drafting team removed Requirement R4, Part 4.3.**
10. **Thank you for the comment.**
11. **In Figure 5 of the Application Guidelines, it is necessary to check for coordination issues with Protection System settings associated with Breakers A, B, C, and D if there are reverse tripping elements that are independent of communications systems.**

Organization	Yes or No	Question 9 Comment
12. The drafting team believes that the requirements of PRC-027-1 extend to only to "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements for the BES and that require coordination for isolating those faulted Elements." As stated in the text for Figure 1 of the Application Guidelines, the only Interconnected Element identified is the transmission line between Breakers A and E. **13. A Misoperation is not a violation of this standard.** **14. The Transmission Owner is identified as the entity responsible for performing the Fault current studies in Requirement R2, Part 2.1. The standard does not address incorrect modeling of a generator's short circuit capability.** **15. Thank you for your support.** **16. Thank you for your reminder and your comments.**		
Detroit Edison		1. It is suggested that the standard include other relevant information that could be needed for a protection system study such as critical clearing times determined from stability studies. 2. In Figure 3, what Protection System Studies would be required if the Distribution Provider does not have a Protection System designed to protect BES transmission system elements? 3. Also, please clarify if the transformers in Figures 3 and 4 are BES elements. 4. Also, further clarification, including some examples, would be beneficial to explain what does and what does not constitute "Protection Systems installed to protect Transmission System Elements" by a Distribution Provider.
Response: Thank you for your comment. **1. The drafting team believes that the data required by a protection system study are discussed in the technical guideline is a suggested list. Other information such as critical clearing times may be required for a specific location's relay coordination study and can be requested by either entity as needed.** **2. The note in the description for Figure 3 states: "A Protection System Study is required per this standard for this example if a Protection System at the Distribution Provider's substation is designed to detect Faults on the BES Transmission System."**		

Organization	Yes or No	Question 9 Comment
Therefore, a Protection System Study would not be required. . **3. The drafting team believes the transformers in Figures 3 and 4 are not BES Elements.** **4. Based on your comment, the drafting team has added a note to the text of Figure 3.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)		It would seem that M9 should be reworded slightly so that it is clear that the compliance burden is placed on the party sending the confirmation. It seems like it should read "demonstrating the confirmation was sent within the respective time frames" instead of "demonstrating the confirmation was achieved within the respective time frames." In other words, Requirement 4 compliance is solely for the confirming party to show evidence, not the submitting party.
Response: Thank you for your comment. **Based on comments, the drafting team revised Measure M9 to read: "Acceptable evidence for R4, Part 4.1 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement."**		
Lincoln Electric System		1. LES recommends additional clarity be added to explain how an entity would coordinate the efforts of the many different protection schemes - for example, pilot tripping, primary, secondary, ground overcurrent, breaker failure, LOP supervised, etc. - to determine only Elements required to isolate Faults are removed from service. Does an entity consider only its fastest scheme, slowest scheme, or all of them? 2. Additionally, is an entity to consider contingencies such as primary or secondary relay out of service, loss of communications, etc.? What about backup tripping? Until the above is addressed, an entity will have a difficult time discerning what exactly needs to be studied. 3. Please take into consideration that system protection is a complicated subject and each entity has its own philosophies on how to do it. Entities should be allowed to use their individual engineering judgment when designing their

Organization	Yes or No	Question 9 Comment
		systems and ensuring it will work to their own standards as well as in compliance with the NERC standards. 4. LES is concerned that there may be potential for mis-coordination between PRC-027-1 and PRC-004-2a. If a misoperation is defined as tripping too much out of service during an event, does the entity become instantly non-compliant with PRC-027-1 since it should have been studied not to do so? Any correlation between these two standards should be considered and clearly defined. 5. LES recommends the 24 month timeframe specified in R2.1 be extended to 60 months. Historically, fault currents tend to increase gradually over time; therefore, an entity may never see a 10% increase between studies, but will most likely see a 10% increase over a larger timeframe at which point they would never be required to perform a study.

Response: Thank you for your comment.

1. **In your example, all relays responding to Fault conditions should be included in your Protection System Study.**
2. **All relays responding to Fault conditions installed for the Interconnected Element should be included in your Protection System Study.**
3. **The drafting team agrees with your assessment that each entity has its own philosophies on how to protect the system. The drafting team believes that PRC-027-1 does not infringe on the ability of entities to protect their elements. However, the purpose of PRC-027-1 is "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults."**
4. **A Misoperation is not a violation of this standard.**
5. **The drafting team believes as stated in the rational for Requirement R2 Part 2.1 that, "Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation." Specific to your question, please note that the 10% deviation is in relation to the most recent Protection System Study.**

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td>Massachusetts Municipal Wholesale Electric Company</td><td></td><td>MMWEC endorses the comments submitted by NPCC.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

See the response to comments submitted by NPCC.</td></tr>
<tr><td>NPPD</td><td></td><td>1. On page 6 and 16 there are statements such as “no evidence there is widespread miscoordination between Interconnected Facilities...” and on page 16 “Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” Clarify what the need is for this standard? This proposed standard significantly increases the record keeping requirements and subsequent resources needed for each Facility owner but does not appear to have a justification.

2. I find the numerous time lines will create significant confusion and very complex data retention practices that will be difficult to track and difficult to audit. It appears the focus is more on time lines and the likely result is the content of the shared information will likely suffer due to the burden of tracking communications between entities. This draft standard includes time lines ranging from “prior to in service date, 30 days, 60 days, 90 days, 6 months, 2 years and 3 years”. I suggest fewer and longer time lines with the focus on if the sharing of information took place and not on when did it take place.

3. The SDT statement below should be generalized to the standard as a whole:

”The SDT believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the SDT sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated</td></tr>
</table>

Organization	Yes or No	Question 9 Comment
		project on schedule and confirm the changes are acceptable "prior to the in-service date," 4. Clarify the size of generation for Distribution Providers that would make this standard applicable for all involved entities. I would expect that the BES phase II definition or registry criteria would be referenced.
Response: Thank you for your comment. **1. The drafting team stands by the quoted statement that there is "no evidence of widespread miscoordination between Interconnected Elements." However, because communication of changes at the interconnection or changes that effect the Protection Systems at an Interconnected Element is required for proper coordination, The drafting team believes the requirements laid out in the standard are appropriate.** **2. The drafting team believes that to make PRC-027-1 measurable and enforceable, the listed times are necessary.** **3. The drafting team believes they applied reasonable and appropriate time frames for the identified activities and provided flexibility by including the option to agree upon an alternate schedule where deemed appropriate.** **4. Figure 3 is independent of the size of the generation. The intent is to identify that coordination is required where Protection Systems are installed for the purpose of detecting Faults on the Transmission System.**		
ExxonMobil Research & Engineering		PRC-001-3 has a single requirement with no associated measure. Any standard requirement whose implementation can address a reliability gap in the Bulk Electric System should possess a quality that can be measured. The SDT should modify PRC-001-3 and provide a measure for Requirement R1 or redact the standard in its entirety.

Response: Thank you for your comment. **This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".**		
Progress Energy		Progress Energy request re-evaluation of time for performing Short circuit study in R 2.1. Request 36 months which is same time frame in R1.
Response: Thank you for your comment. **Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation.**		
Dairyland Power Cooperative		R2, 2.1 "Perform a short circuit study to determine the present Fault current values, not less than once every24 months." is excessive. Yes, short circuit databases are updated annually or even more frequently at times based on system changes. However, to require a full short circuit study every 24 months is too frequent. Changes on the system don't necessarily warrant a full short circuit study, but maybe a study for the affected area. This is adding an unnecessary burden to the industry.
Response: Thank you for your comment. **Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation at the interconnecting buses. The drafting team believes studies associated with changes that would affect the coordination in less time would be triggered by other requirements in this standard.**		
MRO NSRF		1. Recommend that the wording of R2 need be modified to allow a grace period for implementation, as was done in R1. As written, R2 requires an immediate short circuit study, even if no protection system study is required by R1.1.1. 2. The SDT, on both page 6 and 16 states that there is "no evidence there is widespread mis-coordination between Interconnected Facilities..." They

		further state on page 16 that "Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations." Why, then, is this standard even needed? It adds an onerous burden of record keeping on each Facility owner without justification for doing so. 3. Since these are still zero defect standards, should exceptions be included for required operational replacements due to events (e.g. such as storms or immediate equipment replacement). When the lights are out and a technician replaces a CT or VT with a slightly different ratio but compensates by altering the relay settings, there is no way to perform an instant system protection study when the equipment change out was required to support system reliability. The NSRF understands that a "planned" changed be studied before hand, but how will this be viewed when a change is needed that is "unplanned"? Please clarify
Response: Thank you for your comment. 1. **Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation at the interconnecting buses. Based on your comment, the drafting team modified Requirement R2, Part 2.1 to read: "At least once every 24 months, perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."** 2. **The drafting team is developing a standard based on a SAR accepted by the Standards Committee and is addressing directives issued by FERC in Order 693.** 3. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Requirement R3, Part 3.3 was changed to "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Manitoba Hydro		1. Regarding R1, it is not clear what specifically the Protection System Study should include. - According the application guidelines on page 17, it states:

		"Data used to determine Fault currents in performing the study", what data does this refer to? 2. Also it states that it should include "listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Interconnected Facility, and were reviewed for coordination of protective relays as part of the study". It is not clear if it should include a list of all the enabled protection elements and their settings of the protection system package or the package only. Should it include the protection system on the interconnected facilities only or on the immediate adjacent elements as well? 3. The Application guidelines say it should list any issues associated with the relay settings. It is not clear what should be considered as issues. Does a protection mis-coordination occur only under contingencies (such as primary protection element fails) consider an issue? Do backup protection elements have to coordinate with backup protection elements? 4. Regarding R2, it is not clear what fault current value should be used for the short circuit study. Should it be the total fault current of the interconnecting bus? Or should it be the total fault current of the interconnecting bus excluding the contribution from the interconnected facilities?

Response: Thank you for your comment.

1. **The drafting team declines to modify the definition of the Protection System Study but did add the following to the description in the "Guidelines and Technical Basis": "System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions." The drafting team believes that the full description in the Guidelines and Technical Basis is now adequate and appropriate.**
2. **The entity should include all protection elements reviewed for coordination. It is up to the entity to determine what and where those elements are for the particular system configuration.**
3. **It is up to the Owner to determine what is appropriate for their system and under what contingencies the relays should coordinate. Any issued identified that fall outside of their normal practice would need to be listed.**
4. **The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus**

where a Protection System Study is available per Requirement R1."		
ReliabilityFirst		ReliabilityFirst offers the following comments for consideration: 1. Requirements R1, R2 and R4 a. Requirements R1, R2 and R4 do not follow the format of a typical Results Based Standard requirement (i.e. the parent requirement simply states "the entity shall:"). Result Based Standard risk based requirements should be in the following format: "who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome." ReliabilityFirst recommends modifying these three standards to conform to the Results Based Standard format. 2. Requirement R2a. ReliabilityFirst questions why Transmission Owners only need to perform a short circuit study on Interconnected Facilities and not their internal system Facilities as well (Requirement R2). ReliabilityFirst believes it would be beneficial for Transmission owners to be required to determine present fault current values (and calculate the percent deviation between the Fault current values) for all internal system Facilities. 3. Need for PRC-001-1 Requirement R1a. ReliabilityFirst believes PRC-001-1 Requirement R1 is ambiguous and believes the intent is covered in the NERC PER-003-1 standard. It will be very hard for an applicable entity to show that they are "familiar" with the purpose and limitations of protection system schemes applied in its area. Since ReliabilityFirst believes R1 does not enhance reliability, ReliabilityFirst recommends retiring PRC-001-1 Requirement R1 consistent with the effective date of the NERC PER-003-1 standard (effective date of 10/01/2012).
Response: Thank you for your comment. **1. The standard has been reviewed by NERC Quality Review for format and content.** **2. The previous PRC-001 only applied to coordination between TOPs, GOPs and BAs. The drafting team has chosen not to include internal facilities for two main reasons: the extreme documentation burden that would be involved for minimal benefit as most of this work is done by the same organization, and the drafting team believes that the entities' internal facilities are completely in their control and are the responsibility of the entity. Failure to properly design and implement internal Protection Systems would be an internal lack of procedures and/or a human performance issue which are both outside the**		

scope of this standard. **3. This drafting team is not addressing the refinement of PRC-001-1 Requirement 1. As noted in the background section, “The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard”.**		
Kansas City Power & Light		1. Requirement 1.1 of R1 states, “Perform a Protection System Study for each Interconnected Facility to verify that Protection Systems remove from service only those Elements required to isolate Faults as follows:”. The purpose of this standard should not be to remove from service only those Elements required to isolate Faults, therefore 1.1 above should state, “Perform a Protection System Study for each Interconnected Facility as follows:”. 2. Requirement 1.1.2 of R1 states, “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.” Since this Requirement is an action as a result of requirement R2 and as noted in the response to question 6 above, R2 should be deleted. 3. If the SDT is adamant about having a periodic review of fault current levels then the fault current level should be increased to 20% on the protected line. A 10% fault current change is not significant enough to require a new protection system study. 4. Requirements R4.3 and R3.3 are actions as a result of a misoperation and because there is already a standard (PRC-004) that deals with misoperations these two requirements should not be covered in this standard if changes need to be made due to misoperations they should be made in the misoperation standard (PRC-004). This standard is not intended to replace the Misoperation Standard and any requirements addressing misoperations gives FERC, NERC and the Audit Teams the wrong impression of the intent of this standard. 5. All Protection System Studies are dependent on accurate system models.

		Individual Entities should not be responsible for development and maintenance of an accurate Regional model or model to be used between Regions. Individual Entities should only be responsible for providing the information on their system to the Regional Entity so that an accurate model can be maintained by the RC. I propose that this standard be applicable to the Region and require the Region to maintain an accurate model that includes zero sequence impedance and is useful for Protection System Studies. This system model also needs to be accurate between Regions for Protection System Studies that span between Regions. This will require that the standard also be applicable to NERC RRO and require RRO to oversee the process of maintaining an accurate national model or equivalents that can be used between Regions. Anything less than this is placing an unfair burden and unrealistic expectation on the TO to produce and maintain an accurate model for interconnecting Protection System Studies. 6. A dispute resolution mechanism also needs to be required to provide for instances where entities cannot come to a mutual agreement. Recommend a requirement be included for entities to request applicable RC(s) to arbitrate to bring resolution to a matter.

Response: Thank you for your comment.

1. **The drafting team has modified Requirement R1, Part 1.1 to read "Perform a Protection System Study for each Interconnected Element to coordinate Protection Systems, such that the least number of power system Elements are isolated to clear Faults as follows:" to be consistent with the Purpose.**
2. **Requirement R1, Part 1.1.2 provides for a time frame to complete a Protection System Study once a notification that the short circuit current at an Interconnected Element has changed. Requirement R2 provides for a periodic review of short circuit currents. This standard will retain this requirement.**
3. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.**
4. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed**

Requirement R4, Part 4.3. The intent of Requirement R3, Part 3.3 is to communicate changes to a Protection System (including those discovered during an investigation) to an Interconnecting Entity as follows: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components." **5. The drafting team believes that individual entities are not responsible for regional models, they are responsible for conveying information on their own equipment and system** **6. The drafting team believes that any conflict resolution should be handled through normal company practices. The drafting team cannot make judgments on compliance.**		
Texas Reliability Entity		1. Requirement R1.1.3: While we agree with the SDT rationale that R3 notifications may occur weeks or years prior to the change, we feel that a time frame should be included in this requirement rather than leaving it open-ended. 2. We suggest that the Protection System Study be completed at least 60 calendar days prior to the in-service date for R3.1 and within 30 days after receiving notification for R3.3. If the SDT agrees with this, then an appropriate VSL should also be drafted.
Response: Thank you for your comment. **1. The drafting team believes there in not a single time frame that would be appropriate for every project and has chosen to not add a time frame.** **2. Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.". Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Associated Electric Cooperative, Inc., JRO00088		1. See SERC Comments 2. Also pertaining to PRC-027-1 Page 2, Terms:, "Interconnected Facilities" definition, proposed change: Replace: "functional, operating, or corporate entities" with: "functional or operating entities" Rationale: In certain cases,

		independent Corporate entity is irrelevant to the planning and operations of these systems. As written, the underlying 6 G&Ts of AECI's JRO could technically and unnecessarily be subjected to this standard for AECI's internal Facilities, and not just Interconnected Facilities between AECI and other non-JRO entities, although AECI's JROs functionally coordinate relay settings much as a large IOU's regional departments would.
Response: Thank you for your comment. 1. **See response to SERC Comments.** 2. **Based on comments, the drafting team changed Interconnected Facilities to Interconnected Elements defined as follows, Interconnected Elements: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.**		
Western Small Entity Comment Group		The comment group agrees with the WECC Position Paper that the standard as written requires excessive and burdensome documentation that is not needed to demonstrate coordination.
Response: Thank you for your comment. **The drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.**		
PPL Corporation NERC Registered Affiliates		The cutoff date of 6/18/07 for grandfathering of studies may be appropriate for TOs and DPs in light of changes over time to their systems, but the studies that originally established GO relay settings would still be valid where the equipment has stayed the same. For the reasons discussed above, there should be no applicability of PRC-027 to independent GOs, and no changes to PRC-001-1.1 because the applicable requirements.
Response: Thank you for your comment. **The drafting team modified Requirement R1, Part 1.1.1 to make studies performed prior to 6/18/07 acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2. which now reads: "Provide to**		

the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each Protection System Study."The drafting team believes the applicability of PRC-027-1 is correct and the applicability of PRC-001-3 as revised is correct.		
Santee Cooper		1. The documenting, notification and replies required in this standard will put a significant strain on the time of settings personnel. While we agree that this coordination of data is very important, any simplification of the processes would help ensure that protection system staff has the time to do other critical protective system work, in addition to interconnection studies. 2. Possible suggestions would be change R2 2.1 to a longer time period, since most re-coordinations are due to changes covered in R3. "Not less than once every third year," would fall in well with the audit schedule. Not less than once every fifth year would match TPL-001-2 draft 5. 3. Also, you could conceivably not have R3 3.3, since those are covered by the statements in 3.1 and 3.2
Response: Thank you for your comment. 1. **The drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained. The drafting team is not requiring a Protection System Study; only a summary of the results of the Protection System Study performed is required to be provided to the other entities. The drafting team believes the scope of a particular project will dictate the work necessary to coordinate the Protection Systems involved, and to document the coordination process.** 2. **The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require.** 3. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed**		

Requirement R4, Part 4.3. The intent of Requirement R3, Part 3.3 is to communicate changes to a Protection System (including those discovered during an investigation) to an Interconnecting Entity as follows: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."		
Duke Energy		1. The order of the Requirements in PRC-027-1 should be put in chronological order to align with the Example Process outlined on page 22. 2. PRC-001-1:It's not clear that balloting for Project 2007-06 also includes PRC-001-3. 3. General comment - The vague language of R1 does not make it practicable for the responsible entities to implement the requirement. 4. The Purpose is limited to coordination/relationship with the applicable entities. The Purpose is vague as to whether it applies to the Bulk Electric System. 5. Requirement R1 does not clearly state a reliability outcome/benefit. It is not aimed to achieve one objective. The phrase "shall be familiar with the purpose and limitations of protection system schemes," is vague and not measurable. What does it mean to be "familiar" with in this context? Could this requirement be stated in a way that is measurable? The outcome is not obvious because of vague terminology. What will be the outcome of entities being "familiar purpose and limitations of protection system schemes?" The term "familiar" is too general to address a single activity. Although it can be inferred that familiarity with the purpose and limitations helps ensure reliability, what single reliability goal will be accomplished? 6. There is no measure specified for R1 (according to the Model: each requirement must have one or more associate measures used to objectively evaluate compliance with the requirement). What type of evidence could be used so the entities are compliant with the requirement? The Data Retention language mirrors the recommended default language. However, because there are no measures, which are "used as a guide in identifying which

		responsible entity must keep the evidence and for how long," where do the "3 years" come from? There is no supporting document or reference to a supporting document for justification of VRFs for PRC-001-3; although, there is one for PRC-027-1 (which does not mention PRC-001-3).No explanation is given for the "High" or "Severe" VRF for R1.Generally, how is the VSL said to be "Severe" if there are no measures for R1? Effective Date - There needs to be an explanation for the time lapse of more than 3 months between approval date and the effective date of the standard. Additional clarity is needed regarding performance requirements and how an entity would demonstrate compliance with R1.Requirement R1 doesn't support the Purpose statement of the standard.

Response: Thank you for your comment.

1. **The standard has been reviewed by NERC Quality Review for format and content. The Example Process is intended to present one scenario, and the drafting team has decided not to change it.**
2. **This drafting team is not addressing the refinement of PRC-001-3. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".**
3. **It is unclear to the drafting team whether your comment references PRC-001-3 or PRC-027-1. This drafting team is not addressing the refinement of PRC-001-3. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".**
4. **It is unclear to the drafting team whether your comment references PRC-001-3 or PRC-027-1. However, the drafting team has revised the Purpose statement in PRC-027-1. The new Purpose statement reads: To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.**
5. **This drafting team is not addressing the refinement of PRC-001-3. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".**
6. **Based on comments, the drafting team modified the Facility Applicability 4.2 to "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements,"**

which the team believes clarifies those Protection System Elements that are required to be coordinated under this standard.		
Wisconsin Electric Power Company		1. The SDT is to be commended for their efforts in what is a very challenging standard to develop. 2. A Protection System Study by definition must assure that Protection Systems are "coordinated" at an Interconnected Facility. However, this standard does not establish any ownership for achieving a complete study. The interconnected entities are only capable of studying the portion of the system that they own. So, each entity performs their portion of the study and communicates it to the other entities. Thus, there is a lack of clarity in the standard about how the complete study gets done and is documented. With the possible exception of the Transmission Owner, no entity alone has the complete system model that is essential for documenting the complete coordination study. 3. There is also ambiguity on what a complete study looks like, and is subject to interpretation. It is unclear how the supplementary documents previously developed for PRC-001 apply to this standard. In the absence of such guidance, how will consistency be achieved for coordination of Protection Systems on the various types of Interconnection Facilities ? 4. It is suggested that Requirement R4.3 is extraneous and should be removed. If these changes are sufficient to trigger a study, then the timeframe for agreement is already specified in R4.1. We propose that the standard be revised to allow the entities to re-affirm the results of a previous study, when appropriate, rather than needing to perform another study. For example, perhaps the fault current has increased, but the coordination interval between devices is not appreciably changed. 5. The SDT notes in several places in the draft standard (pg 6, 16) that there is no evidence of widespread miscoordination between Interconnected Facilities, nor any evidence of misoperations caused by lack of coordination. 6. This suggests that if this standard is needed, that it should be simpler, less

		prescriptive, and have greater recognition of the motivation for mutual coordination that already exists. It can be argued that the tasks and time frames required in the draft standard should be left to the entities to determine.
Response: Thank you for your comment. 1. **Thank you for your support.** 2. **It is expected that the owner of the Interconnected Element will complete the Protection System Study for that element. See the Figures 1-5 and accompanying explanations.** 3. **The drafting team is not defining what every Protection System Study should look like, just the minimum that must be included into a summary that will be provided to the Interconnected Element Owner.** 4. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.** 5. **PRC-027-1 is replacing Requirements R2 and R3 of PRC-001-2. The drafting team is developing a standard based on a SAR accepted by the Standards Committee and is addressing directives issued by FERC in Order 693.** 6. **The drafting team believes that there is flexibility in the process to allow for the expertise of each entity to be used to coordinate Protection Systems.**		
ISO RTO Council SRC		The SDT recognizes that Requirement R1 falls outside the scope of Project 2007-06 and proposes that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. Left unaddressed, entities may be reluctant to vote to approve the PRC-001-2 changes. Changes made to a standard can cause unforeseen or unintended consequences that cannot be addressed because of limitations in the scope of the project. The SDT has no ability to address the matter without getting a change in scope of the project. This is a concern that applies to ALL standards changes as the industry seeks to revise and improve the NERC standards. A change in the Rules of Procedure or the Standards Development Procedures must be in place to recognize and deal with such occurrences. The SDT (SRC?) is also concerned that these proposed requirements are not

		conducive to NERC's stated goal of making the reliability standards more "results or performance oriented". Although many of the actions embodied in the proposed requirements should be performed, they are administrative in nature and do not in and of themselves provide results that will impact reliability. The industry needs to discuss and come to agreement on what reliability standards should look like in order to meet the NERC stated goal. The SRC also believes these requirements are not applicable for entities operating in the ERCOT Interconnection.
Response: Thank you for your comment. **This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-2, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".** **The drafting team believes the documentation identified in the requirements is necessary to support the purpose.** **The drafting team believes PRC-027-1 applies to all applicable entities that own Protection Systems within ERCOT.**		
MWDSC		The standard requires more documentation than is necessary and providing a copy of each Protection System Study is burdensome and would not result in better performance. It should be adequate to document that studies were performed and that affected entities have agreed to the results.
Response: Thank you for your comment. **The wording of Requirement R1, Part 1.2 is "Provide to each affected Interconnected Element owner a summary of the results of each Protection System Study performed pursuant to this requirement…" Transmitting the entire PSS is not required. The receiving entity per Requirement R4 Part 4.1 shall "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Colorado Springs Utilities		1. The wording of the text under Applicability suggests that Interconnected Facilities include coordination and documentation of Transmission to Distribution interfaces. Since these are often located in different functional or

		corporate entities we feel this would require more documentation, and therefore needs clarified. 2. There are no specifications on what constitutes a significant change to a Protection System; is it a CT ratio change, a relay replacement, or anything to the whole system? For example, would a single structure replacement require notification as a line spacing change? The wording sounds good but lacks specifics that would make this a workable standard.
Response: Thank you for your comment. 1. **The standard is only applicable to Distribution Providers with "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements."** 2. **The drafting team believes when changes that "modifies the conditions used in the coordination of Protection Systems of the Interconnected Elements", they must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained. For the example cited in the comment, Requirement R3 Part 3.1 states that "Changes to a transmission system Element that changes any sequence or mutual coupling impedance" and therefore would be included in the communication.**		
ATCO Electric		There are too many timelines that are hard to keep up with. The drafting team should reduce amount of timelines to a manageable amount.
Response: Thank you for your comment. **The drafting team will continue to restrain the number of timelines, however the drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.**		
Liberty Electric Power LLC		There is no generator size limit set for this standard. It should exclude generators below a threshold value. Suggest generators with an aggregate nameplate value below 500 MVA connecting through a single step-up transformer.
Response: Thank you for your comment. **The drafting team has modified the Applicability Section 4.2 Facilities to read: "Protection Systems installed for the purpose of**		

detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements". Consequently, the standard is applicable to Generator Owners that have the Facilities described above.		
Portland General Electric Company		1. This standard, as written, requires an inordinate amount of documentation that this not in line with current fault study and protection coordination tools. When combined with the timelines, this will require a complete rework of the existing processes used for protection coordination and an additional full time protection engineer. We have no history of misoperations on interconnecting lines or of backup protection on such lines to justify any additional effort to document coordination. 2. R1 leaves open to interpretation what constitutes coordination, with many unanswered questions. What is an acceptable coordination margin? How many contingencies need to be considered? Does loss of communication need to be considered? For the evidence, would an exception report showing no coordination intervals are violated be acceptable for the "summary results of each Protection System Study"? 3. Will the responsibilities outlined in the Application Guidelines be included as part of the final standard? These may not be in line with current practices. How will this requirement be audited across utilities with different coordination practices? 4. R2 requires significant cooperation between interconnecting utilities, with each keeping track of what fault currents are being used by the other. This is not in line with the use of joint system models, allowing more frequently updated fault currents to be used. Currently, the individual system models are updated by some utilities daily then they are reconciled at least annually. Protection System Studies can be run any time in between model reconciliation, with all local changes accounted for. 5. R3.1 does not provide guidance on the timing of notification for changes; the measure M6 indicates this is for future changes, but the requirement does not.

		6. Protection engineers are rarely notified in advance of transmission line changes resulting from such things a road widenings and pole replacements. Providing this information to neighboring utilities in advance will require significant changes to line design processes. Thresholds must be established to rule out minor transmission line changes that do not significantly impact the line impedance (and thus the fault current); perhaps a 10% change in impedance would be more appropriate than the general "changes to line lengths and/or conductor size or spacing". 7. This requirement should also include changes to facility ratings to ensure PRC-023 compliance. 8. R4 requires a significant change to work practices to support capital construction schedules and allow interconnecting utilities 30 days to review changes. The schedule laid out does not account for disagreements that lead to back-and-forth prior to achieving agreement. This requirement grants power to neighboring utilities to halt construction activities which could, in turn, create compliance violation of other Reliability standards.

Response: Thank you for your comment.

1. **The drafting team will continue to restrain the number of timelines, however the drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.**
2. **It is up to the Owner to determine what margins are appropriate for their system and under what contingencies the relays should coordinate.**
3. **The Application Guidelines are and will be part of the standard and are consistent with the requirements of the standard. The figures in the Application Guidelines are intended to be explanatory.**
4. **The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate. This does not preclude an entity from performing this task more often.**
5. **The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated.**

6. The drafting team believes when a change "modifies the conditions used in the coordination of Protection Systems of the Interconnected Elements", it must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained. For the example cited in the comment, Requirement R3 Part 3.1 states that "Changes to a transmission system Element that change any sequence or mutual coupling impedance" and therefore would be included in the communication. **7. The drafting team believes that FAC-009 already requires the sharing of Facility Ratings and their inclusion into the Protection System coordination standard is unnecessary.** **8. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.**		
American Electric Power		1. We agree with the comment in the background section that the SAR written for this project was focused on System Protection Coordination, and we recommend that PRC-001 R1 should be moved to another standard more focused on operations or training. TOP-006 R3 might be a more appropriate standard for such a requirement. 2. For R1, the standard needs to clearly state the boundaries of the required study(ies). In addition, detail is needed regarding the depth of study away from the point of interconnection, and how far into the generating unit auxiliary system or interconnecting system must be evaluated. 3. Based on the redline provided where R3 and R4 have been removed, and assuming the SDT is not willing to moving the sole remaining requirement to another standard, the title and purpose of resulting PRC-001 would need to be changed. 4. If PRC-001 R1 remains as it is, the phrase "familiar with the purpose and limitations of protection system schemes" needs additional clarity. Doing so might help prevent a CAN from being developed to provide such clarity.

		5. AEP suggests the time requirement on R4.3 associated with R3 needs to be extended to 60 days.
Response: Thank you for your comment. 1. **This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, “The SPC SDT recommends that Requirement R1 remain in PRC-001-2, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard”.** 2. **Based on comments, the drafting team modified the Facility Applicability 4.2 to “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements”, which the team believes clarifies those Protection System Elements that are required to be coordinated under this standard.** 3. **This drafting team is not addressing the refinement of PRC-001. As noted in the background section, “The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard”.** 4. **This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, “The SPC SDT recommends that Requirement R1 remain in PRC-001-2, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard”.** 5. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Consumers Energy		1. We feel that this is a very difficult standard to interpret consistently as written. We think a negative vote is warranted since it is confusing and unclear for our situation. Following are specific comments to support our negative vote. 2. In regard to the Process Flow Chart on page 21 - We assume this Process Flow Chart is intended as an illustrative clarification of the standard, not a supplement to the wording. The chart claims to be a “complete representation of the process” and as such should match identically or it should be eliminated as it causes confusion. It is our interpretation that the chart does not match the standard’s wording. One example if you start with an R3 emergency replacement you end up with two conflicting results.

		Under 4.3.2 you have 30 days to confirm that the changes are acceptable. Under 1.1.3 you have to do a protection study so you are given 90 days per section 1.2. This entire chart should be verified to ensure that it matches the written standard and does not result in conflicting requirements. We suggest adding the sub-requirement labels to each flow chart item for easier reference to that section of the standard. 3. In regard to Figure 3 on page 25 - The figure appears to represent the connection of a large NERC qualified generator. Does this figure also apply to a looped source distribution system or should that follow figure 4? We would like to see a definitive example that clarifies what to do for the situation where you have a looped source distribution system. 4. In regard to Figure 4 on page 26 - the figure implies that A & B can be set to overtrip C (as no study is required) which would interrupt the BES for distribution faults. This appears to be contrary to what is intended by this standard.

Response: Thank you for your comment.

1. **The drafting team is striving to improve the standard through the balloting process.**
2. **The drafting team has modified the flowchart based on comments and to reflect all changes made to the standard.**
3. **Figure 3 is represents a generator connected to a Distribution Provider. The drafting team modified Figure 3 to indicate that the source could be a generator or a network system. The Applicability Section 4.2 Facilities states: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements", which the team believes clarifies those Protection System Elements that are required to be coordinated under this standard. This does not include a Protection System that would operate for a Fault on the Transmission System, if that is not its primary purpose. Figure 4 is intended to be a radial Distribution System with no source.**
4. **Figure 4 is intended to illustrate a situation where no Protection System Study is required per this standard because there is no Protection System installed to detect Faults on the BES Transmission System. This does not preclude the Transmission Owner from reviewing the Protection System to ensure the system operates as designed.**

Public Service Enterprise		We have the following additional comments:

Group		a. FORMATTING: Remove the bullets in 3.1 and replace with subparts 3.1.1, 3.1.2, etc. b. With regard to R2, we suggest that the Transmission Planner be required to perform the studies described therein, not the TO. c. Furthermore, there should be a requirement similar to that suggested in our response to #5, paragraph that each TP provide data needed by another TP needed to perform the required study. It should also address how potentially different results for the same Interconnected Facility by the several TPs should be dealt with.
Response: Thank you for your comment. **a. The drafting team has retained the format for Requirement R3, Part 3.1.** **b. Although the Transmission Planner may "define system protection and control needs", it will be the owner that is responsible for determining the implementation and coordination.** **c. The drafting team believes that nothing in the requirements precludes an entity from asking for necessary data, and requirements are needed to ensure that requested data is provided. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2. The drafting team believes that documentation is necessary in order to have a record that the coordination study was completed, communicated to the appropriate Entities and agreed upon.**		
Public Utility District No. 1 of Snohomish County		We note that the formulas in R2 use V for current. For clarity's sake, we believe current should be denoted using the letter I
Response: Thank you for your comment. **Per your suggestions and others, the drafting team has modified the equation to replace "V" with "I".**		
Sacramento Municipal Utility District		We note that the formulas in R2 use V for current. For clarity's sake, we believe current should be denoted using the letter I.
Response: Thank you for your comment. **Per your suggestions and others, the drafting team has modified the equation to replace "V" with "I".**		

Tri-State G & T		We think there needs to be a time frame associated with the calculation of the percent deviation after the fault duties are calculated. One way to accomplish that would be to eliminate 2.1 and add a 24 month requirement to 2.2., which would require the performance of a short circuit study anyway.
Response: Thank you for your comment. **The drafting team believes that the phrase "pursuant to Requirement R2, Part 2.1, using the following equation" implies that the calculation must be performed within the same 24 month period. As stated in the Rationale box supporting Requirement R2, Part 2.1: "Short circuit databases are customarily updated annually, so the SDT believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation."**		
NV Energy		While we agree the Protection System Studies are necessary to verify coordination of Protection Systems, we believe that the proposed Standard requires more than the necessary amount of documentation, and therefore becomes administratively burdensome. This is contrary to the principles of the Results-Based Standards. We suggest that the evidence be limited to evidence that studies were coordinated and that the applicable entities have agreed to the results of the studies.
Response: Thank you for your comment. **The drafting team believes that documentation is necessary in order to have a record that the coordination study was completed, communicated to the appropriate Entities and agreed upon. Requirement R4 Part 4.2 has been modified to read "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes." The measure for Part 4.2 is M9, which now reads "Acceptable evidence for R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that confirmation of agreement was achieved prior to implementation of any planned Protection System(s) changes."**		
Exelon		None

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Draft 1 of SAR posted for comment June 11, 2007 – July 10, 2007.
2. SAR approved on August 13, 2007.
3. First posting of revised standard PRC-001-2 on September 11, 2009.
4. Transitioned from a revision of PRC-001-1 to development of PRC-027-1 based on industry comments, Quality Review feedback, and consideration of FERC directives relative to the existing requirements of PRC-001-1.
5. Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPC SDT) created a new results-based standard, PRC-027-1, to coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults. This standard incorporates and enhances the coordination aspects of Requirements R3 and R4 from PRC-001-1 (now R2 and R3 of PRC-001-2). The SPC SDT is requesting a posting for stakeholder comments under a 30-day formal comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period with Parallel Successive Ballot	November 2012
Recirculation Ballot	January 2013

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. For Interconnected Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2007-06 – PRC-027-1	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here.

The following terms are defined for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

Interconnected Element: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.

Protection System Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Coordination for Performance During Faults**

2. **Number:** PRC-027-1

3. **Purpose:** To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2 Facilities:

   Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements

5. **Background:**

On December 7, 2006, the NERC Planning Committee approved the assessment of Reliability Standard PRC-001 – System Protection Coordination, prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF noted problems with the applicability to entities and vagueness of requirements in the existing PRC-001-1 reliability standard. The SPCTF concluded that the deficiencies of Reliability Standard PRC-001-1 were magnified by having requirements that addressed coordination of protection functions and capabilities in the operating and planning timeframes. Consequently, the SPCTF recommended that the requirements for the operating horizon and planning horizon be clearly delineated, and possibly divided into two standards.

The NERC Standards Committee approved a Standard Authorization Request that included the modifications noted by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC SDT) posted an initial draft of Reliability Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC SDT attempted to address all issues identified by the SPCTF assessment of PRC-001-1. The SPC SDT responded to the comments from the initial posting of PRC-001-2, and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC Quality Review (QR) in December 2010. Based on the results from the QR, and after informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to follow the SPCTF recommendation and focus their knowledge and expertise on developing a new results-based standard, concentrating on the reliability aspects (the coordination of new and existing protective systems in the planning horizon) associated with Requirements R3 and R4 of PRC-001-1. These aspects of coordination are incorporated and enhanced in the proposed Reliability Standard PRC-027-1 – Protection System Coordination for Performance During Faults with the stated purpose:

> *"To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults."*

PRC-001-1 contained a non-specific training requirement (Requirement R1), three operating time frame requirements (Requirements R2, R5 and R6), and two planning requirements (Requirements R3 and R4). The SPC SDT transferred the responsibility of addressing the operating Requirements R2, R5, and R6 to the drafting team for Project 2007-03 Real-time Operations, charged with revising the TOP group of reliability standards. The Project 2007-03 drafting team retired Requirements R2, R5, and R6 of PRC-001-1 because they address data and data requirements that are included in the proposed Reliability Standard TOP-003-2. The SPC SDT is incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 in a new standard (as recommended by the SPCTF assessment), and focusing on the performance of Protection Systems during Faults. Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) will be retired upon appropriate regulatory approval of the proposed standards PRC-001-3 and PRC-027-1. The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard.

Additionally, the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address "the appropriate use of time delays in relays," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination.

Other Aspects of coordination of Protection Systems addressed by other Projects:

Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects.

- Underfrequency Load shedding programs are addressed by PRC-006-1 (Project 2007-01 Underfrequency Load Shedding – pending FERC approval) and generator performance during frequency excursions is being addressed by PRC-024-1 in Project 2007-09 Generator Verification.
- Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed by PRC-024-1 in Project 2007-09, Generator Verification.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is being addressed by PRC-019-1 in Project 2007-09.

- Transmission relay loadability is addressed in PRC-023-1 and, pending FERC approval, PRC-023-2.
- Generator relay loadability will be addressed by Phase 2 of Relay Loadability: Generation, in Project 2010-13.2.
- Protective relay response during power swings will be addressed in Phase 3 of Project 2010-13.3, Relay Loadability.
- Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and will be improved in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

The SPC SDT believes that including these other aspects of protection coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

1.1. Perform a Protection System Study for each Interconnected Element on its System as follows:

1.1.1 Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists.

1.1.2 Within six calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required.

1.1.3 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 or Part 3.3, or technically justify why such a study is not required.

1.2. Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).

Rationale for R1:

Part 1.1 Protection System Studies are necessary to verify coordination of Protection Systems for existing and new Interconnected Element. The drafting team defines the term "Interconnected Element" as "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity."

Part 1.1.1 The drafting team believes 48 months is an appropriate period of time for entities to perform the Protection System Studies required where no study exists. The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame.

Part 1.1.2 The drafting team believes that 6 months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater Fault current deviation at an interconnecting bus, where such conditions may warrant a new Protection System Study, or to technically justify why no such study is required, e.g., when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current.

Part 1.1.3 The drafting team believes that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, or to technically justify why no such study is needed. The drafting team believes the timeframe associated with this requirement is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3 is unnecessary because notification of such a change may occur weeks or years prior to the change. The initiating entity has the incentive to provide the identified information as soon as possible to ensure timely implementations.

Part 1.2 The drafting team believes to properly ensure coordination of Protection Systems associated with Interconnected Element(s), all entities need to share the summary of results of a Protection System Study (PSS) and assess the study results. The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSS performed in accordance with Requirement R1 to the owner(s) of the Protection System(s) associated with the Interconnected Element(s).

M1. Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1. and 1.1.2, and 1.1.3 is a dated Protection System Study, or the summary results of each Protection System Study (either in hard copy or electronic file formats) demonstrating that the time frames specified in Parts 1.1.1. and 1.1.2. Acceptable evidence of technical justification for not performing a Protection System Study as specified in Parts 1.1.2 and 1.1.3 could be documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any aspects of coordination.

M2. Acceptable evidence for Requirement R1, Part 1.2 demonstrating that the summary results of each Protection System Study (hard copy or electronic file formats) was provided within the specified time frame to the owner(s) of the Protection System(s) associated with the Interconnected Element(s).

R2. For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

2.1. At least once every 24 months:

2.1.1 Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1.

2.1.2 Calculate the percent deviation between the Fault current values (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1.1, using the following equation:

$$\% \, Deviation = \left| \frac{Iscs - Ipss}{Ipss} \right| x \; 100$$

Where: I_{scs} = Fault current value from present short circuit study

> Rationale for R2: This requires a periodic review of Fault currents at the interconnecting bus and providing to the results to the applicable entities when deviations occur that meet the Requirement R2 criteria. It is important that interconnected Facility owners are kept aware of changes that could affect proper performance of their Protection Systems. The Transmission Owner is identified as the entity responsible for performing the short circuit studies because they maintain the data necessary to perform the studies. The drafting team determined that 10% was an appropriate point to provide this information based on the fact that Protection Systems are typically set with margins above 10%.
>
> Part 2.1 Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation. The drafting team believes studies associated with changes that would affect the coordination in less time would be triggered by other requirements in this standard. The drafting team is including this formula to assure a consistent approach is used by each Transmission Owner when calculating the percent deviation in Fault current vales.
>
> Part 2.2 The drafting team believes the 30-day time frame is reasonable for providing the Fault current information to the owner(s) of the Protection System(s) associated with the Interconnected Element.

And: I_{pss} = Fault current value used in the most recent Protection System Study

2.2. Within 30 calendar days after identification where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates a deviation in Fault current of 10% or greater, provide each owner of the Protection System associated with the Interconnected Element the updated Fault current values (I_{scs}).

M3. Acceptable evidence for Requirement R2, Part 2.1 is dated documentation (hard copy or electronic file formats) that contains the present Fault current values from the short circuit study for each interconnecting bus analyzed and that identifies the percent deviation from the most recent Protection System Study Fault current values determined by the formula.

M4. Acceptable evidence that the updated Fault current values (I_{scs}), along with documentation (hard copy or electronic file formats) for Requirement R2, Part 2.2 was provided within the specified timeframe to each owner of the Protection System associated with the Interconnected Element.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnected Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

3.1. Details for any change or additions listed below; either at an existing or new Facility associated with the Interconnected Element; or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).

- New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios

Rationale for R3: This requires the transfer of appropriate information to the entities associated with each Interconnected Element due to circumstances identified in Parts 3.1, 3.2, and 3.3.

Part 3.1 The reliability objective of this requirement is to enable the process of conducting Protection System Studies by ensuring that the information is provided to the owner(s) of the Protection Systems associated with Interconnected Element(s). The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. Examples of changes to generator units that result in impedance changes could include replacements and re-ratings. This requirement also pertains to changes identified as a result of studies performed in Part 1.1.

Part 3.2 The purpose of this requirement is to provide a means for an entity to receive the requested information in a timely manner in order to perform a Protection System Study, as required in Parts 1.1.1, 1.1.2, and 1.1.3. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide this information. The requirement also provides some flexibility for the parties involved to determine an otherwise agreed-to schedule, if appropriate.

Part 3.3 The drafting team believes 30 calendar days is sufficient time to provide the information.

- Changes to a transmission system Element that change any sequence or mutual coupling impedance
- Changes to generator unit(s) that result in a change in impedance
- Changes to the generator step-up transformer(s) that result in a change in impedance

3.2. Requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 calendar days of receiving a request or according to an agreed-upon schedule.

3.3. Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.

M5. Acceptable evidence may include, but is not limited to, a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) in hard copy or electronic file formats as identified in the bulleted list for Requirement R3, Part 3.1 was provided to each responsible entity connected to the same Interconnected Element.

M6. Acceptable evidence for Requirement R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was provided according to the agreed-upon schedule, or within 30 calendar days absent such an agreement.

M7. Acceptable evidence for Requirement R3, Part 3.3 is dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the changes made was provided within 30 calendar days.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.

4.2. Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.

Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with Interconnected Elements confirm that the Protection System(s) applied are acceptable per the conditions identified in Parts 4.1 and 4.2.

Part 4.1 The drafting team believes 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with Interconnected Elements to review the summary results of a Protection System Study. If any issues are identified that require changes then respond whether further action is required.

Part 4.2 The drafting team believes that proposed modifications (including project schedules) to Facility changes associated with the Interconnected Element, as described in Requirement R3, Part 3.1, must be communicated and accepted prior to the in-service date. Acceptance assures that the coordination of Protection Systems associated with the affected Interconnected Element is achieved.

M8. Acceptable evidence for Requirement R4, Part 4.1 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement.

M9. Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that confirmation of acceptance was achieved prior to implementation of any planned Protection System(s) changes.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System at an Interconnected Facility shall keep data or evidence to show compliance with Requirements R1, R2, R3, and R4, and Measures M1 through M9, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System at a Facility associated with an Interconnected Element is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity performed a Protection System Study on an Interconnected Element per R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Study at an interconnecting bus per R1, Part 1.1.2, or documented why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by 10 calendar days or less.	The responsible entity performed a Protection System Study on an Interconnected Element per R1, Part 1.1.1, but was late by more than 30 calendar days. OR The responsible entity performed a Protection System Study at an interconnecting bus per R1, Part 1.1.2, or documented why a study was not required, but was late by more than 30 calendar days but less than or equal to 40 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity performed a Protection System Study at an interconnecting bus per R1, Part 1.1.2, or documented why a study was not required, but was late by more than 40 calendar days but less than or equal to 50 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity performed a Protection System Study at an interconnecting bus per R1, Part 1.1.2, or documented why a study was not required but was late by more than 50 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 30 calendar days. OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The responsible entity failed to perform a Protection System Study on an Interconnected Element per R1, Parts 1.1.1, 1.1.2, or 1.1.3, or document why a study was not required. OR The responsible entity failed to provide Protection System Study results in accordance with R1, Part 1.2.
R2	Long-term Planning	Medium	The Transmission Owner performed a short circuit study, as described in R2, Part 2.1, but was late by less than or equal to 30 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 40 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 40 calendar days but less than or equal to 50 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 50 calendar days. OR The Transmission Owner failed to perform a short circuit study, as described in R2, Part 2.1. OR The Transmission Owner failed to calculate the percent deviation between the Fault currents, according to the formula designated in

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element the changes in Fault currents, as described in R2, Part 2.2, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element the changes in Fault currents, as described in R2, Part 2.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element the changes in Fault currents, as described in R2, Part 2.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	R2, Part 2.1. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element the changes in Fault currents, as described in R2, Part 2.2, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnected Element the changes in Fault currents.
R3	Operations Planning	Medium	The responsible entity provided the requested information per R3, Part 3.2, but was late by 10	The responsible entity provided the requested information per R3, Part 3.2, but was late by more	The responsible entity provided the requested information per R3, Part 3.2, but was late by more	The responsible entity failed to provide information to the owner(s) of the Facility associated with the Interconnected Element for any proposed change identified in R3.1. OR The responsible entity provided the requested information per R3, Part 3.2, but was late by more

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			calendar days or less. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by 10 calendar days or less.	than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	than 30 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the requested information.
R4	Operations Planning	Medium	The responsible entity confirmed acceptance of the summary results of the Protection System Study per R4, Part 4.1, but was late by 10 calendar days or less.	The responsible entity confirmed acceptance of the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity confirmed acceptance of the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity confirmed acceptance of the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 30 calendar days. OR The responsible entity failed to confirm acceptance of the summary results of the Protection System Study per R4, Part 4.1. OR The responsible entity failed to confirm

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						acceptance of the planned changes pursuant to R4, Part 4.2 prior to implementation of those changes.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

This requirement directs the performance of Protection System Studies for every Interconnected Element to verify coordination of existing Protection Systems where no recent study exists or when Facility configuration or Fault current deviations of 10% or more have occurred. In developing the language to define Protection System Study, the System Protection Coordination Standard Drafting Team (SPC SDT) considered various reference books discussing protective relaying theory and application, along with the following description of "coordination of protection" from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Using the reference material cited above as guidance, the drafting team defined the term Protection System Study for use within the PRC-027-1 Reliability Standard as:

> "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults."

Protection System Studies comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), and adequate directional polarizing quantities.

The drafting team believes applicable entities should have a documented Protection System Study for each Interconnected Element to validate the Protection Systems associated with those Interconnected Elements perform in a manner consistent with the purpose of this Standard. Additionally, the drafting team believes that 48 months is an appropriate amount of time for entities to perform the initial studies expected under this requirement. This period considers the time some entities may require to create project scopes, acquire proposals, and secure contracts to hire external resources that may be needed to perform the studies. The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with Interconnected Elements that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.

Parts 1.1.2 and 1.1.3 further direct that Protection System Studies must be completed under the following two circumstances:

1. After notification of an identified 10% or greater deviation in Fault current, the notified entities must perform a new Protection System Study of the Interconnected Element or document why a study is not required. The drafting team recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater deviation in Fault current may not necessitate a new Protection System Study be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the six-month time frame associated with this requirement represents a reasonable period to perform the studies that are required after identification by the 24-month Fault current review.
2. After proposing or being notified of a change at a Facility associated with the Interconnected Element, entities must perform a new Protection System Study, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the proposed change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new Protection System Study be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the timeframe associated with this requirement is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3 is unnecessary because notification of such a change may occur weeks or years prior to the change due to the wide variety of conditions that may be associated with a particular change. The drafting team sees the entity initiating any change as having the incentive to move this along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2.

Requirement R1, Part 1.2 directs the entity performing the Protection System Study to provide a summary of the study results to the affected Interconnected Element owner(s). As guidance, the drafting team lists the following inputs and results of a Protection System Study that may be included in the summary provided pursuant to this requirement:

1. A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Facility, and were reviewed for coordination of protective relays as part of the study including the contingencies used in the evaluation.

2. Data used to determine Fault currents in performing the study, along with a listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Facility under study.
3. A listing of any issues associated with the relay settings of the other owner(s) at the Facility that were identified by the study.
4. Any proposed revisions to a Protection System or its protective relay settings that were identified by the study.

Requirement R2:

The drafting team investigated various inputs that would trigger a review of the existing Protection System Studies and determined, through the experience of the drafting team members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated Protection System Study may be necessary. These variations could result from the accumulation of incremental changes over time. This requirement mandates a periodic review of Fault currents and includes the calculation of the percent deviation between the Fault current values used in the most recent Protection System Study and the present Fault current values indicated by the short circuit study performed pursuant to this requirement. This calculation is necessary to identify Fault current changes that must be communicated in accordance with Requirement R2, Part 2.2.

Polling of drafting team membership and various protection engineering committees indicates that short circuit databases are customarily updated annually. Based on this information, the drafting team believes that requiring a 24-month periodic review of Fault currents provides entities additional flexibility to schedule and perform these studies and calculate the percent deviation, as described in Requirement R2, Part 2.1. The drafting team believes studies associated with changes that would affect the coordination in less than 24 months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.2 further directs the Transmission Owner to, within 30 calendar days, inform each owner of the Facility associated with the Interconnected Element when short circuit studies indicate that 10% deviations in Fault current have occurred at the interconnecting bus(s). The drafting team believes the 30-day time frame associated with this requirement is reasonable for providing the Fault current information to the interconnected entity(s) and is consistent with other NERC reliability standards.

In Requirement R2, the Transmission Owner is identified as the Functional Entity responsible for performing the Fault current studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners’ short circuit models.

Requirement R3:

This directs the registered functional entity initiating any change to provide the details to the other affected entities of the Interconnected Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes. Documentation provided to these other owners may include, but is not limited to, power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings. The recipient will incorporate the applicable information into its Protection System Studies to evaluate whether changes are required.

The list of applicable changes provided in Requirement R3, Part 3.1 is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. The drafting team recognizes that Facility changes at other locations can impact the Protection System Study of the Facility associated with the Interconnected Element; e.g., the addition of a large autotransformer bank or generator not directly associated with the Interconnected Element. The drafting team believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the drafting team sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable “prior to the in-service date,” as stipulated by Requirement R4, Part 4.2.

Requirement R3, Part 3.2 allows for entities to agree upon a schedule, appropriate to the circumstances, for providing the details needed to conduct a Protection System Study or, absent such agreement, within 30 days of a request for this information. This requirement provides a means for entities to receive requested information in a timely manner. In consideration of circumstances where the information may not be readily available or may be incomplete due the retirement of personnel, the purging of records, change of ownership, etc., it also provides the flexibility of mutually agreeing to a schedule for exchanging information. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide the requested information where no other agreement exists.

Additionally, this requirement includes a provision for providing details associated with changes to the previously agreed-upon coordination when changes are made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components Based upon the limited number of instances that would occur under such circumstances, the drafting team believes 30 calendar days after determining that changes are required is an appropriate time frame for providing the associated details to affected entities.

Requirement R4:

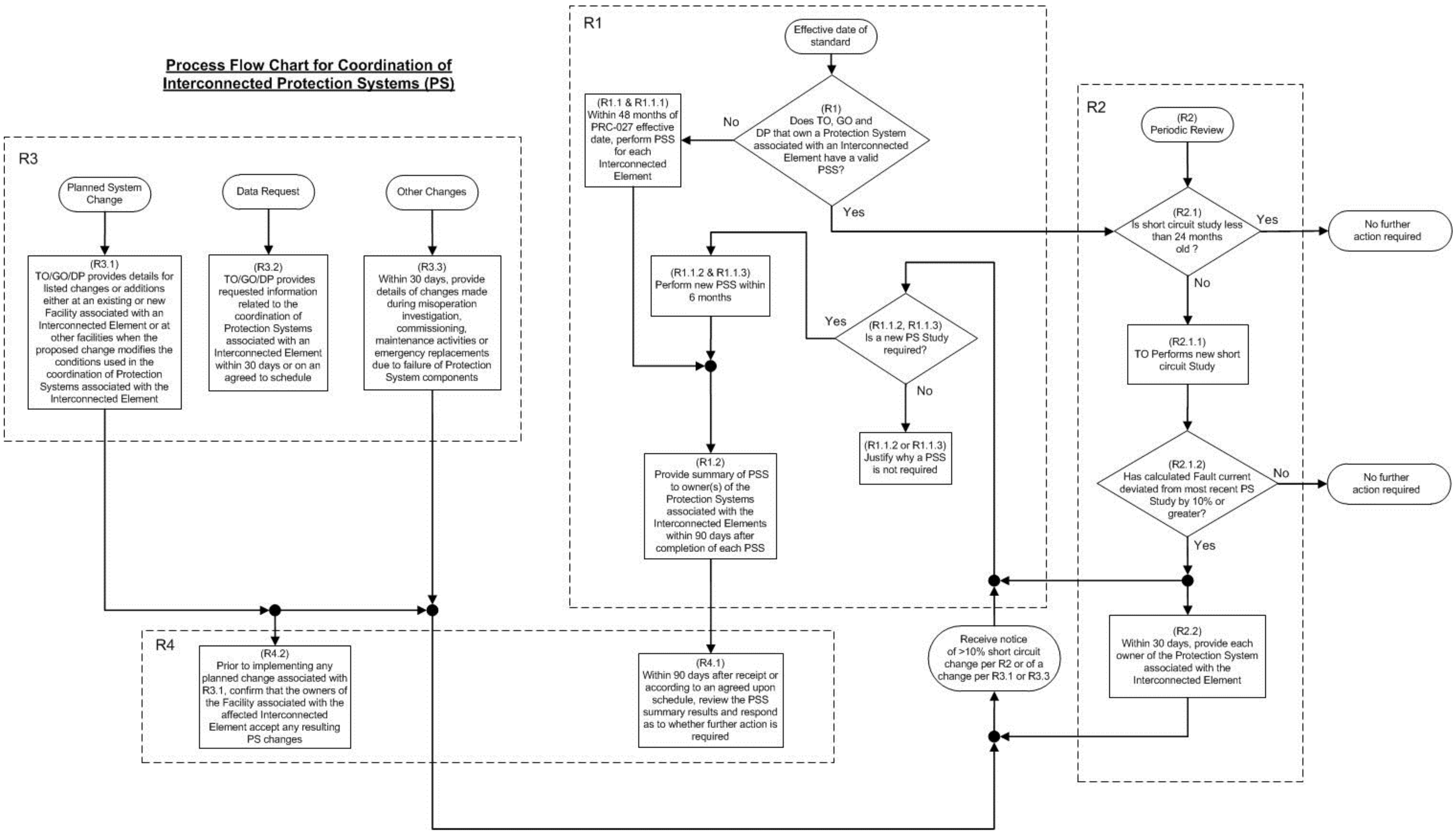
The reliability objective of this requirement is to bring the process of Protection System coordination full circle by gaining the confirmation of interconnected entities that their

Protection Systems are coordinated consistent with the purpose of this standard. Cooperative participation of Facility owners in communicating Protection System(s) design, and study results will achieve coordination of Protection Systems for reliable operation of the BES during Faults.

Requirement R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2; or absent acceptance propose revisions to achieve acceptable results. The drafting team believes 90 calendar days after receipt of the results of a Protection System Study provides a reasonable time for the owners of Facilities to resolve differences and confirm acceptance that their Protection Systems are coordinated.

Requirement R4, Part 4.2 directs entities to confirm that planned changes described in Requirement 3.1 are acceptable prior to the in-service date of those changes. The purpose of this requirement is to assure the effects that planned changes have on Protection Systems at a Facility associated with the affected Interconnected Element have been considered by all affected entities.

Process Flow Chart: Below is a complete representation of the process, including the relationships between requirements:



Example Process

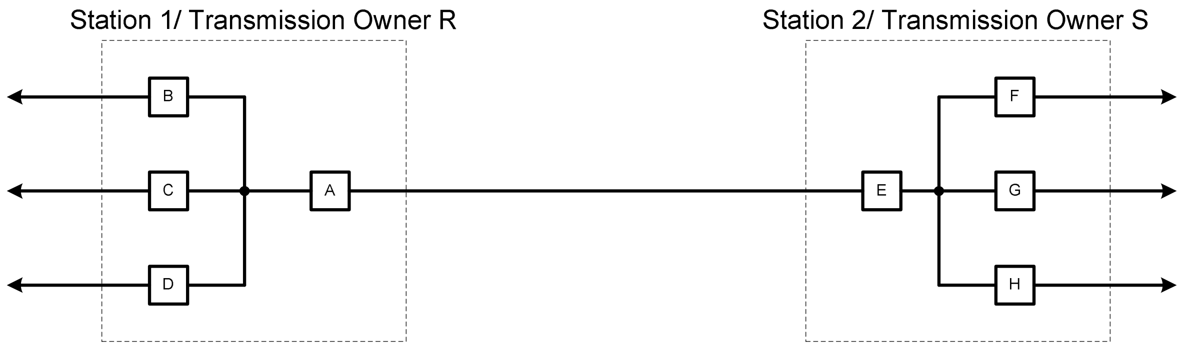
An example of the interaction between entities required to gather the information to perform an accurate study is below.

- The initiating entity (Entity A) will contact the interconnected entity (Entity B) and request up-to-date Protection System information.
- Upon receipt of the above request for information, Entity B will provide the information within 30 calendar days, or an agreed upon time frame.
- Entity A will perform a Protection System Study using the information received.
- Entity A will provide a summary of the results of the study to Entity B within 90 calendar days of completing the Protection System Study.
- Entity B will review the summary information and, within 90 calendar days of receiving the study results from Entity A, confirm agreement that coordination is achieved.
    - In cases where the study reveals that changes to Protection Systems are needed, Entity B would propose to Entity A revisions that achieve acceptable results.
- Documentation of the final agreement is required prior to implementation of planned changes.

Diagrams

Introduction: The diagrams below are intended to provide guidance related to the purpose of this standard between owners of Facilities associated with the affected Interconnected Element. After the reviews and prior to implementation of the changes, the owners must reach agreement on the final settings to achieve coordination of the Protection Systems.

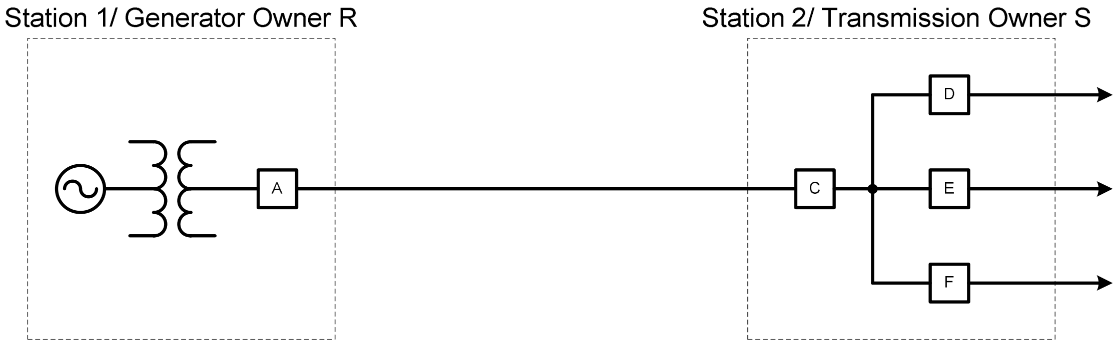
Figure 1



In Figure 1 above, the Interconnected Element between the Transmission Owners is the transmission line between Breakers A and E.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 1, Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers E, F, G, and H. Likewise, Owner R is to review the Protection System settings associated with Breaker E (provided by Owner S) for coordination issues with the Protection System settings associated with Breakers A, B, C, and D.

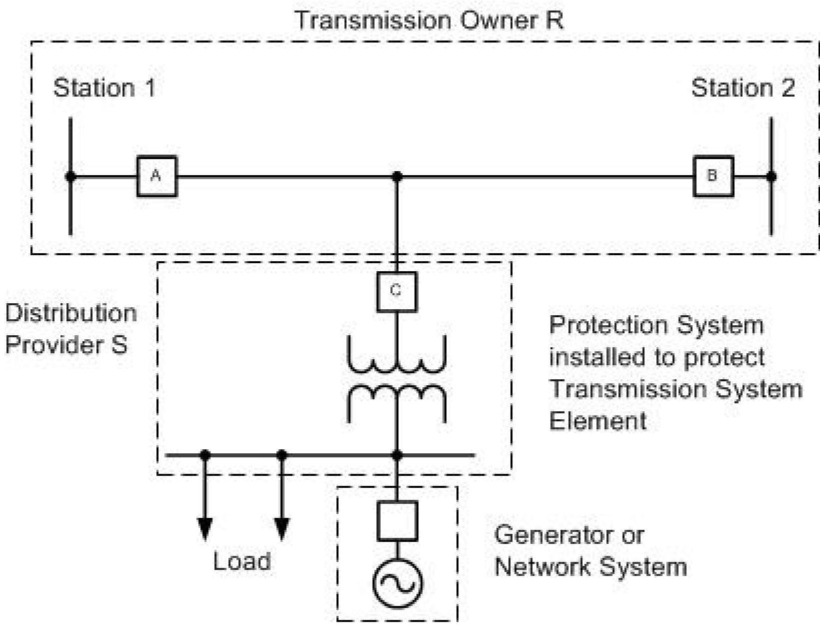
Figure 2



In Figure 2 above, the Interconnected Element between the Transmission Owner and the Generator Owner is the transmission line or bus between Breakers A and C.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 2, Transmission Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, Generation Owner R is to review the Protection System settings associated with Breaker C (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

Figure 3



In Figure 3 above, the Interconnected Element between the Transmission Owner and the Distribution Provider is the transmission line or tap between the line and Breaker C.

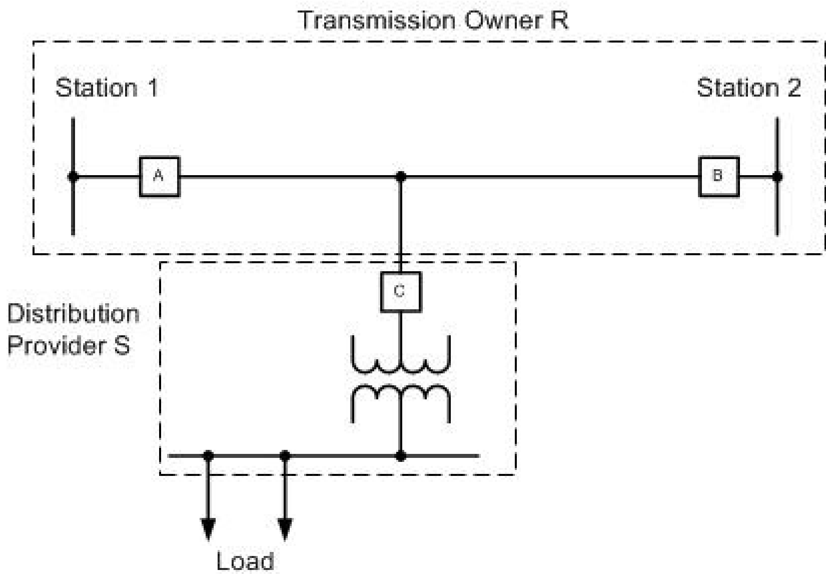
Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 3, Transmission Owner R is to review the Protection System settings associated with Line Breaker C (provided by Distribution Provider S) for coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2.

Notes:

A Protection System Study is required per this standard for this example if a Protection System at the Distribution Provider's substation is designed to detect Faults on the BES Transmission System.

"Protection Systems installed to detect faults on the BES Transmission System" are not inclusive of those relays that may operate for such faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.). As an example, reverse power relays are often installed to detect situations where the transmission source becomes de-energized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a Fault on a BES Element, they are not "installed to detect faults on the BES Transmission System."

Figure 4

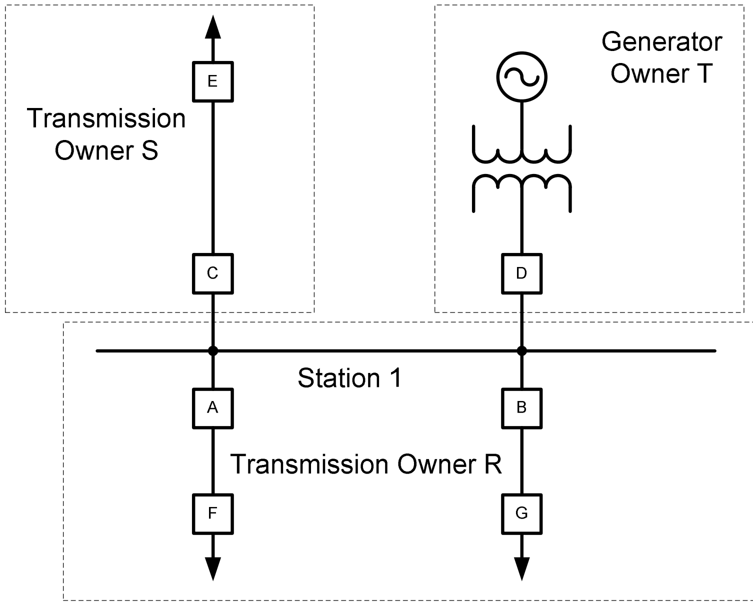


In Figure 4 above, the Interconnected Element between the Transmission Owner and the Distribution Provider is the transmission line or tap between the line and Breaker C.

Note: No specific Protection System Study is required per this standard for this example since the Protection System at the Distribution Provider's substation is not designed to protect BES transmission system Elements.

Figure 5

Transmission/Generation Facility with Multiple Owners



In Figure 5 above, the Interconnected Element between the Transmission Owners R and S and the Generation Owner T is the common Transmission bus. In this example, Transmission Owner S and Generator Owner T are not directly interconnected to each other at Transmission Station 1, and all direct interconnections are between Owner R and each of the other Owners connected to the bus.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 5:

Owner R is to review the Protection System settings associated with Breaker C, E, D, and the generator Protection System (provided by Owners S or T) for coordination issues with the Protection System settings associated with Breakers A, B.

Owner S is to review the Protection System settings associated with Breakers A, F, B, G, D, and the generator Protection System (provided by Owners R or T) for coordination issues with the Protection System settings associated with Breaker C. To perform this review, it will be necessary that Transmission Owner R provide Owner S with its settings for Breakers A, F, B, and G, as well as the settings for Breaker D and generator Protection System settings provided to Owner R by Generator Owner T.

Owner T is to review the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R or S) for coordination issues with the Protection System settings associated with Breaker D or the Protection Systems associated with generator Protection Systems. In order to perform this review, it will be necessary that Transmission Owner R provide Generator Owner T with its settings for Breakers A, F, G, and B, as well as the settings for Breaker C and E provided to Owner R by Transmission Owner S.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Draft 1 of SAR posted for comment June 11, 2007 – July 10, 2007.
2. SAR approved on August 13, 2007.
3. First posting of revised standard PRC-001-2 on September 11, 2009.
4. Transitioned from a revision of PRC-001-1 to development of PRC-027-1 based on industry comments, Quality Review feedback, and consideration of FERC directives relative to the existing requirements of PRC-001-1.
5. Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPC SDT) created a new results-based standard, PRC-027-1, to coordinate Protection Systems ~~utilized to protect~~for Interconnected ~~Facilities~~Elements, such that ~~those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the~~ the least number of power system ~~performance specified within requirements established in other approved NERC Reliability Standards~~Elements are isolated to clear Faults. This standard incorporates and enhances the coordination aspects of Requirements R3 and R4 from PRC-001-1~~.~~ (now R2 and R3 of PRC-001-2). The SPC SDT is requesting a posting for stakeholder comments under a 30-day formal comment period.

Anticipated Actions	Anticipated Date
~~Post first draft of standard for 30-day Formal Comment Period.~~	~~May 2012~~
~~45-day Formal Comment Period with Parallel Initial Ballot~~	~~August 2012~~
30-day Formal Comment Period with Parallel Successive Ballot	November 2012
Recirculation Ballot	January 2013

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is ~~three~~six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where ~~such explicit approval is required. Where no~~ regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is ~~three~~six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise ~~prescribed by~~made effective pursuant to the laws ~~or regulations of the~~ applicable to such ERO governmental authorities. For ~~Facility interconnections~~Interconnected Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-~~-~~approved effective date.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2007-06 – PRC-027-1	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. ~~*New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*~~

The following terms are defined for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

Interconnected ~~Facilities~~~~: BES Facilities~~**Element**: An Element that ~~are~~ electrically ~~joined by one or more Element(s) and~~ joins separate Functional Entities, including those Functional Entities that are ~~owned by different functional, operating, or corporate entities.~~a part of the same Registered Entity.

Protection System Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Coordination for Performance During Faults**
2. **Number:** PRC-027-1
3. **Purpose:** To coordinate Protection Systems for Interconnected ~~Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards~~Elements, such that the least number of power system Elements are isolated to clear Faults.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider

4.2 Facilities:

Protection Systems installed ~~at~~for the purpose of detecting Faults on Interconnected ~~Facilities.~~Elements of the BES and that require coordination for isolating those faulted Elements

5. **Background:**

On December 7, 2006, the NERC Planning Committee approved the assessment of Reliability Standard PRC-001 – System Protection Coordination, prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF noted problems with the applicability to entities and vagueness of requirements in the existing PRC-001-1 ~~Reliability Standard.~~reliability standard. The SPCTF concluded that the deficiencies of Reliability Standard PRC-001-1 were magnified by having requirements that addressed coordination of protection functions and capabilities in the operating and planning timeframes. Consequently, the SPCTF recommended that the requirements for the operating horizon and planning horizon be clearly delineated, and possibly divided into two standards.

The NERC Standards Committee approved a Standard Authorization Request that included the modifications noted by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC SDT) posted an initial draft of Reliability Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC SDT attempted to address all issues identified by the SPCTF assessment of PRC-001-1. The SPC SDT responded to the comments from the initial posting of PRC-001-2, and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft ~~was developed in the results-based format and~~ went through a NERC Quality Review (QR) in December 2010. Based on the results from the QR, and after informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to follow the SPCTF recommendation and focus their knowledge and expertise on developing a new results-based standard, concentrating on the reliability aspects (the coordination of new and existing protective systems in the planning horizon) associated with Requirements R3 and R4 of PRC-001-1. These aspects of coordination are incorporated and enhanced in the proposed Reliability Standard PRC-027-1 – Protection System Coordination for Performance During Faults with the stated purpose:

> *"To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.~~To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.~~"*

PRC-001-1 ~~contains~~contained a non-specific training requirement (Requirement R1), three operating time frame requirements (Requirements R2, R5 and R6), and two planning requirements (Requirements R3 and R4). The SPC SDT transferred the responsibility of addressing the operating Requirements R2, R5, and R6 to the ~~SDT~~drafting team for Project 2007-03 Real-time Operations, charged with revising the TOP group of ~~Reliability Standards.~~reliability standards. The Project 2007-03 ~~SDT is recommending retirement of~~drafting team retired Requirements R2, R5, and R6 of PRC-001-1 because they address data and data requirements that are included in the proposed Reliability Standard TOP-003-2. The SPC SDT is incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 in a new standard (as recommended by the SPCTF assessment), and focusing on the performance of Protection Systems during Faults. Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) will be retired upon appropriate regulatory approval of the proposed standards PRC-001-3 and PRC-027-1. The SPC SDT recommends that ~~the training aspects of PRC-001-1,~~ Requirement R1 ~~be~~remain in PRC-001-3, until its reliability objective is addressed ~~in Reliability Standard PER-005-1 with~~by either a revision to ~~its Applicability section to include the Generator Operator~~an existing standard or development of a new standard.

Additionally, the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address "the appropriate use of time delays in relays~~"~~," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination.

Other Aspects of coordination of Protection Systems addressed by other Projects:

Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects.

- Underfrequency ~~load~~Load shedding programs are addressed by PRC-006-1 (Project 2007-01 Underfrequency Load Shedding – pending FERC approval) and generator performance during frequency excursions is being addressed by PRC-024-1 in Project 2007-09 Generator Verification.

- Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed by PRC-024-1 in Project 2007-09, Generator Verification.

- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is being addressed by PRC-019-1 in Project 2007-09.

- Transmission relay loadability is addressed in PRC-023-1 and, pending FERC approval, PRC-023-2.

- Generator relay loadability will be addressed by Phase 2 of Relay Loadability: Generation, in Project 2010-13.2.

- Protective relay response during power swings will be addressed in Phase 3 of Project 2010-13.3, Relay Loadability.

- Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and will be improved in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

The SPC SDT believes that including these other aspects of protection coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

> Rationale for R1:
>
> Part 1.1 Protection System Studies are necessary to verify coordination of Protection Systems for existing and new Interconnected ~~Facilities.~~Element. The ~~SDT~~drafting team defines the term "Interconnected ~~Facilities~~Element" as "~~BES Facilities~~An Element that ~~are~~ electrically ~~joined by one or more Element(s) and are owned by different functional, operating, or corporate entities~~joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity."
>
> Part 1.1.1 ~~Protection System studies performed after June 18, 2007 (the effective date of PRC-001-1) and in accordance with PRC-001-1, are sufficient to meet Requirement R1, Part 1.1.1.~~The ~~SDT~~drafting team believes ~~that 36~~48 months is an appropriate period of time for entities to perform the ~~studies~~Protection System Studies required where no study exists. The ~~SDT~~drafting team has no evidence there is widespread miscoordination ~~between~~ of Protection Systems associated with Interconnected ~~Facilities~~Elements that warrants a shorter time~~-~~ frame.
>
> Part 1.1.2 The ~~SDT~~drafting team believes that 6 months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater ~~fault~~Fault current deviation at an interconnecting bus, where such conditions may warrant a new Protection System Study, or to technically justify why no such study is ~~needed~~required, ~~i.e.~~e.g., when a line is protected by dual current differential systems with no backup elements set that are dependent upon ~~fault~~Fault current.
>
> Part 1.1.3 The ~~SDT~~drafting team believes that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, or to technically justify why no such study is needed. The drafting team believes the timeframe associated with this requirement is contingent upon the project's scope and schedule. ~~The SDT believes that~~ Sspecifying a time frame for performing studies associated with Requirement R3 is unnecessary because notification of such a change may occur weeks or years prior to the change. The initiating entity has the incentive to provide the identified information as soon as possible to ensure timely implementations.
>
> Part 1.2 The ~~requirement provides for the communication of the~~

1.1. Perform a Protection System Study for each Interconnected ~~Facility~~Element on its System ~~to verify that Protection Systems remove from service only those Elements required to isolate Faults~~ as follows:

1.1.1 Within ~~36~~48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected ~~Facility exists that was performed on or subsequent to June 18, 2007~~Element exists.

1.1.2 Within ~~6~~ six calendar months after determining~~,~~ or being notified of~~,~~ a 10% or greater change in ~~fault~~Fault current ~~for that Interconnected Facility~~at an interconnecting bus, as described in Requirement R2, ~~unless the entity can demonstrate~~or technically justify why such a study is not required.

1.1.3 According to an agreed upon time frame to meet the schedule w~~W~~hen proposing or being notified of a change ~~at the Interconnected Facility~~, as described in Requirement R3, Part 3.1 or Part 3.3 ~~unless the entity can demonstrate~~, or technically justify why such a study is not required.

1.2. Within 90 calendar days after the completion of each Protection System Study ~~Provide~~ provide to ~~each affected Interconnected Facility~~ the owner~~,~~(s) of the Protection

System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the ~~Protection System(s)~~protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)~~ within 90 calendar days after the completion of each Protection System Study~~.

M1. Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1. and 1.1.2, and 1.1.3 is a dated Protection System Study, or the summary results of each Protection System Study (either in hard copy or electronic file formats) demonstrating that the ~~meeting the timeframes~~time frames specified in Parts 1.1.1. and 1.1.2~~., or documentation demonstrating why a study is not required~~. Acceptable evidence of technical justification for ~~changes described~~not performing a Protection System Study as specified in Parts 1.1.2~~.~~ and 1.1.3 could be documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any aspects of coordination.

~~**M2.**~~ Acceptable evidence for Requirement R1, Part 1.2 demonstrating ~~for Requirement R1, Part 1.2. is dated documentation demonstrating each affected entity received, within the specified time frame,~~that the summary results of each Protection System Study (hard copy or electronic file formats) ~~sent pursuant~~was provided within the specified time frame to ~~Requirement R1, Part 1.2.~~

M2. ~~For each~~ the owner(s) of the Protection System(s) associated with the Interconnected ~~Facility, each~~Element(s).

R2. For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

2.1. ~~Perform~~At least once every 24 months:

2.1.1 Perform a short~~-~~circuit study to determine the present ~~fault current values, not less than once every twenty-four months~~maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is

Rationale for R2: This currents at the interconnec to the applicable entities w Requirement R2 criteria. Facility owners are kept a proper performance of the Transmission Owner is id performing the short circu data necessary to perform determined that 10% was information based on the f typically set with margins

Part 2.1 Short circuit datal annually, so the drafting te entities flexibility to sched studies and calculate the p believes studies associated coordination in less time w requirements in this standa formula to assure a consis Transmission Owner whe Fault current vales.

Part 2.2 The drafting team reasonable for providing t owner(s) of the Protection Interconnected Element.

~~Rationale for R2: This requires a periodic review of fault currents and notification to the applicable entities when deviations occur that meet the Requirement R2 criteria. It is important that Interconnected Facility owners are kept aware of changes that could affect proper performance of their Protection Systems. The Transmission Owner is identified as the entity responsible for performing the fault current studies because they maintain the data necessary to perform the studies. The SDT determined that 10% was an appropriate point at which to require notification based on the fact that Protection System elements that can be affected by fault current are typically set with margins above 10%.~~

~~Part 2.1 Short-circuit databases are customarily updated annually, so the SDT believes 24 months provides the entities flexibility to schedule and perform the new short-circuit studies and calculate the percent deviation. The SDT believes studies associated with changes that would affect the coordination in less time would be triggered by other requirements in this standard.~~

~~Part 2.2 The SDT is requiring this formula to assure a consistent approach is used by each Transmission Owner when calculating the percent deviation in fault current vales.~~

~~Part 2.3 The SDT believes the 30-day time frame is reasonable for sending notification(s) to the interconnected entity(s).~~

available per Requirement R1.

~~2.1.1~~

2.1.2 Calculate the percent deviation between the ~~fault~~Fault current values (single line to ground and 3-phase for the interconnecting bus~~(s) or Element~~(s) under consideration) used in the most recent Protection System Study and the ~~fault~~Fault current values determined pursuant to Requirement R2, Part 2.1.1, using the following equation:

$$\cancel{\% \, Deviation = \left(\frac{Vscs - Vpss}{Vpss}\right) x \, 100}$$

$$\% \, Deviation = \left|\frac{Iscs - Ipss}{Ipss}\right| x \, 100$$

Where: ~~V_{scs} =~~ I_{scs} = Fault current value from present short-circuit study

And: ~~V_{pss} =~~ I_{pss} = Fault current value used in the most recent Protection System Study

~~2.1.~~**2.2.** Within 30 calendar days after identification ~~Where~~ where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates a deviation in ~~fault~~Fault current of 10% or greater, ~~notify~~provide each owner of the Protection System associated with the Interconnected ~~Facility at which the 10% or greater deviation applies,~~Element the updated Fault current values (I_{scs}) ~~within 30 calendar days after identification~~.

M3. Acceptable evidence for Requirement R2, Part 2.1 is dated documentation (hard copy or electronic file formats) that contains~~ing~~ the present ~~fault~~Fault current values from the short-circuit study for each ~~Interconnected Facility~~interconnecting bus analyzed and that identifies the percent deviation from the most recent Protection System Study Fault current values determined by the formula.

~~**M4.** Acceptable evidence for R2, Part 2.2 is dated documentation (hard copy or electronic file formats) that identifies the percent deviation from the most recent Protection System Study fault current values determined by the formula pursuant to Part 2.2.~~

~~**M5.**~~**M4.** Acceptable evidence ~~for R2, Part 2.3 is documentation (hardcopy or electronic file formats) demonstrating identification of a deviation in fault~~that the updated Fault current values ~~10% or greater~~(I_{scs}), along with documentation (hard copy or electronic file formats) ~~demonstrating each affected entity received notification of such~~for Requirement R2, Part 2.2 was provided within the specified timeframe to each owner of the Protection System associated with the Interconnected Element.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each ~~Transmission Owner, Generator Owner, and Distribution Provider~~ Transmission Owner, Generator Owner, and Distribution Provider connected to ~~each Interconnected Facility, the details~~the same Interconnected Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

~~**R3.**~~ Details ~~(e.g., project schedule, protective relaying scheme types and settings) as follows: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

Rationale for R3: This requires the transfer of appropriate information to the entities ~~of~~associated with each Interconnected ~~Facility~~Element due to circumstances identified in Parts 3.1, 3.2, and 3.3.

Part 3.1 The reliability objective of this requirement is to enable the process of conducting Protection System Studies by ensuring that the information is provided to the owner(s) of the Protection Systems associated with Interconnected ~~Facility owner(s) in a timely manner.~~Element(s). The ~~SDT~~drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. Examples of changes to generator units that result in impedance changes could include replacements and re-ratings. This requirement also pertains to changes identified as a result of studies performed in Part 1.1.

Part 3.2 The purpose of this requirement is to provide a means for an entity to receive the requested information ~~from an interconnected owner~~ in a timely manner in order to perform a Protection System Study, as required in Parts 1.1.1, 1.1.2, and 1.1.3. The ~~SDT~~drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide this information. The requirement also provides some flexibility for the parties involved to determine an otherwise agreed~~-~~to schedule, if appropriate.

3.1. ~~For~~for any change or additions listed below; either at an existing or new Facility associated with the Interconnected ~~Facility,~~Element; or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems ~~of~~associated with the Interconnected ~~Facilities.~~Element(s).

- New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios
- Changes to ~~line lengths and/or conductor size or spacing~~
- ~~Additions, removals, or replacements of~~ a transmission system Element~~(s)~~ that change any sequence or mutual coupling impedance
- Changes to generator unit(s) ~~including replacements, re-ratings, and impedances~~that result in a change in impedance
- ~~Replacement of~~ Changes to the generator step-up transformer(s) that result in a change in impedance

3.2. ~~According to an agreed upon schedule~~Requested information related to the coordination of Protection Systems associated with ~~a Transmission Owner, Generator Owner, or Distribution Provider, or absent such an agreement,~~an Interconnected Element within 30 calendar days of receiving a request ~~for information~~or according to an agreed-upon schedule.

~~3.3.~~ Within 30 calendar days~~ after:~~

~~3.3.1 Corrections are~~ , details of changes made ~~when~~to Protection ~~System errors are found~~Systems during Misoperation investigations, commissioning, ~~or~~ maintenance activities~~.~~

~~3.4.~~3.3. ~~Emergency~~, or emergency replacements ~~are~~ made due to failures of Protection System components.

~~M6.~~**M5.** ~~Acceptable evidence for R3, Part 3.1 is documentation (hard copy or electronic file formats) demonstrating each affected entity received project details for the changes identified in the bulleted list. Evidence~~Acceptable evidence may include, but is not limited ~~to~~ to, a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) in hard copy or electronic file formats as identified in the bulleted list for Requirement R3, Part 3.1 was provided to each responsible entity connected to the same Interconnected Element.

~~M7.~~**M6.** Acceptable evidence for Requirement ~~r~~ R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was ~~delivered~~provided according to the agreed~~-~~-upon schedule~~,~~ or within 30 calendar days absent such an agreement.

~~M8.~~**M7.** Acceptable evidence for Requirement R3, Part 3.3~~ and its subparts~~ is dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the changes made ~~pursuant to Parts 3.3.1 and 3.3.2.was received~~was provided within 30 calendar days.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Within 90 calendar days after receipt, ~~confirm agreement with~~or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2~~.~~, and respond as to whether further action is required.

~~4.2.~~ Prior to ~~the in-service date of~~ implementing any planned change ~~at the Interconnected Facility, confirm the affected Interconnected Facility owners agree~~(s) associated with ~~the Protection System(s) changes as described in~~ Requirement R3, Part 3.1~~.~~

Rationale for R4: This requirement ensures ~~owners~~owner(s) of Protection System(s) associated with Interconnected ~~Facilities~~Elements confirm that the Protection System(s) applied ~~on each of its Interconnected Facilities is~~are acceptable per the conditions identified in Parts 4.1~~, 4.2,~~ and 4.~~3~~2.

Part 4.~~1 The SDT~~1 The drafting team believes ~~ninety (~~90~~)~~ calendar days is a reasonable time for the ~~owners~~owner(s) of Protection System(s) associated with Interconnected Elements to review the summary results of ~~existing Interconnected Facilities to resolve differences and reach agreement~~a Protection System Study. If any issues are identified that require changes then respond whether further action is required.

Part 4.2 The ~~SDT~~drafting team believes that proposed modifications (including project schedules) to Facility changes associated with the Interconnected ~~Facilities~~Element, as described in Requirement R3, Part 3.1~~,~~ must be communicated and ~~agreed~~

~~4.3. Within 30 calendar days after receipt:~~

~~4.3.1 Confirm the Protection System(s) changes are acceptable pursuant to notification received per Requirement R3, Part 3.3.1.~~

~~4.4.~~4.2. ~~Confirm the~~, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes ~~are acceptable pursuant to notification received per Requirement R3, Part 3.3.2~~.

M8. Acceptable evidence for Requirement R4, ~~Parts~~Part 4.1~~, 4.2, and 4.3~~ is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement.

M9. Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that confirmation of acceptance was achieved ~~within the respective timeframe(s).~~prior to implementation of any planned Protection System(s) changes.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~Regional Entity or if the Responsible Entity is owned, operated or controlled by the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity) to be responsible for compliance enforcement.~~

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System at an Interconnected Facility shall keep data or evidence to show compliance with Requirements R1, R2, R3, and R4, and Measures ~~M1through~~M1 through M9, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System at a Facility associated with an Interconnected ~~Facility~~Element is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity performed a Protection System Study on an Interconnected ~~Facility~~Element per R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Study ~~on~~at an ~~Interconnected Facility~~interconnecting bus per R1, Part 1.1.2, or documented why a study was not required, but was late by less than or equal to ~~10~~30 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by 10 calendar days or less.	The responsible entity performed a Protection System Study on an Interconnected ~~Facility~~Element per R1, Part 1.1.1, but was late by more than 30 calendar days. OR The responsible entity performed a Protection System Study ~~on~~at an ~~Interconnected Facility~~interconnecting bus per R1, Part 1.1.2, or documented why a study was not required, but was late by more than ~~10~~30 calendar days but less than or equal to ~~20~~40 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to	The responsible entity performed a Protection System Study ~~on~~at an ~~Interconnected Facility~~interconnecting bus per R1, Part 1.1.2, or documented why a study was not required, but was late by more than ~~20~~40 calendar days but less than or equal to ~~30~~50 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity performed a Protection System Study ~~on~~at an ~~Interconnected Facility~~interconnecting bus per R1, Part 1.1.2, or documented why a study was not required but was late by more than ~~30~~50 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 30 calendar days. OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				20 calendar days.		The responsible entity failed to perform a Protection System Study on an Interconnected ~~Facility~~Element per R1, Parts 1.1.1, 1.1.2, or 1.1.3, or document why a study was not required. OR The responsible entity failed to provide Protection System Study results in accordance with R1, Part 1.2.
R2	Long-term Planning	Medium	The Transmission Owner performed a short-~~-~~circuit study, as described in R2, Part 2.1, but was late by less than or equal to 30 calendar days.	The Transmission Owner performed a short-~~-~~circuit study as described in R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 40 calendar days.	The Transmission Owner performed a short-~~-~~circuit study as described in R2, Part 2.1, but was late by more than 40 calendar days but less than or equal to 50 calendar days.	The Transmission Owner performed a short-circuit study as described in R2, Part 2.1, but was late by more than 50 calendar days. OR The Transmission Owner failed to perform a short-circuit study, as described in R2, Part 2.1. OR The Transmission Owner failed to calculate the percent deviation between the ~~fault~~Fault

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner ~~notified~~provided the owner(s) of the Facility associated with the Interconnected ~~Facility owner of~~Element the changes in ~~fault~~Fault currents, as described in R2, Part 2.2, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner ~~notified~~provided the owner(s) of the Facility associated with the Interconnected ~~Facility owner of~~Element the changes in ~~fault~~Fault currents, as described in R2, Part 2.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner ~~notified~~provided the owner(s) of the Facility associated with the Interconnected ~~Facility owner of~~Element the changes in ~~fault~~Fault currents, as described in R2, Part 2.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	currents, according to the formula designated in R2, Part 2.~~2~~1. OR The Transmission Owner ~~notified~~provided the owner(s) of the Facility associated with the Interconnected ~~Facility owner of~~Element the changes in ~~fault~~Fault currents, as described in R2, Part 2.2, but was late by more than 30 calendar days. OR The Transmission Owner failed to ~~notify~~provide the owner(s) of the Facility associated with the Interconnected ~~Facility owner of~~Element the changes in ~~fault~~Fault currents.
R3	Operations Planning	Medium				The responsible entity failed to provide information to the ~~owners~~owner(s) of the ~~interconnected Facilities~~Facility associated with the Interconnected Element for any proposed change

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The responsible entity provided the requested information per R3, Part 3.2, but was late by 10 calendar days or less. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by 10 calendar days or less.	The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	identified in R3.1. OR The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the requested information.
R4	Operations Planning	Medium	The responsible entity confirmed ~~agreement with~~acceptance of the summary results of the Protection System Study per R4, Part 4.1, but was late by 10 calendar days or less.	The responsible entity confirmed ~~agreement with~~acceptance of the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity confirmed ~~agreement with~~acceptance of the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity confirmed ~~agreement with~~acceptance of the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 30 calendar days. OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~OR~~ ~~The responsible responded to the confirmation request per R4, Part 4.3, but was late by 10 calendar days or less.~~	~~OR~~ ~~The responsible responded to the confirmation request per R4, Part 4.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.~~	~~OR~~ ~~The responsible responded to the confirmation request per R4, Part 4.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.~~	The responsible entity failed to confirm ~~agreement with~~acceptance of the summary results of the Protection System Study per R4, Part 4.1. OR The responsible entity failed to confirm acceptance of the planned changes pursuant to R4, Part 4.2 prior to implementation of those changes. ~~OR~~ ~~The responsible responded to the confirmation request per R4, Part 4.3, but was late by more than 30 calendar days.~~ ~~OR~~ ~~The responsible entity failed to respond to the confirmation request per R4, Part 4.3.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

This requirement directs the performance of Protection System Studies for every Interconnected ~~Facility~~Element to verify coordination of existing Protection Systems where no recent study exists or when Facility configuration or ~~fault~~Fault current deviations of 10% or more have occurred. In developing the language to define Protection System Study, the System Protection Coordination Standard Drafting Team (SPC SDT) considered various reference books discussing protective relaying theory and application, along with the following description of "coordination of protection" from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Using the reference material cited above as guidance, the ~~SDT~~drafting team defined the term Protection System Study for use within the PRC-027-1 Reliability Standard as:

> "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults."

Protection System Studies comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), and adequate directional polarizing quantities.

The ~~SDT~~drafting team believes applicable entities should have a documented Protection System Study for each ~~interconnected Facility~~Interconnected Element to validate the Protection Systems associated with those Interconnected Elements perform in a manner consistent with the purpose of this Standard. Additionally, the ~~SDT~~drafting team believes that ~~36~~48 months is an appropriate amount of time for entities to perform the initial studies expected under this requirement. This period considers the time some entities may require to create project scopes, acquire proposals, and secure contracts to hire external resources that may be needed to perform the studies. The ~~SDT~~drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with Interconnected

~~Facilities~~Elements that might warrant a shorter time~~-~~ frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.

~~It should be noted that Protection System studies performed after June 18, 2007 (the effective date of PRC-001-1) are sufficient to meet Requirement R1.~~

Parts 1.1.2 and 1.1.3 further direct that Protection System Studies must be completed under the following two circumstances:

1. After notification of an identified 10% or greater deviation in ~~fault~~Fault current, the notified entities must perform a new Protection System Study of the Interconnected ~~Facility~~Element or document why a study is not required. The ~~SDT~~drafting team recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater deviation in ~~fault~~Fault current may not necessitate a new Protection System Study be performed; therefore this part of the requirement includes the statement, ~~"unless the entity can demonstrate that~~"…or technically justify why such a study is not required~~"~~." The ~~SDT~~drafting team believes the ~~6~~six-month time frame associated with this requirement represents ~~is~~ a reasonable period to perform the studies that are required after identification by the 24-month ~~fault~~Fault current review.

2. After proposing or being notified of a change at ~~an~~a Facility associated with the Interconnected ~~Facility~~Element, entities must perform a new Protection System Study, or ~~document~~technically justify why such a study is not required. The ~~SDT~~drafting team recognizes that, based on the scope of the proposed change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new Protection System Study be performed; therefore this part of the requirement includes the statement, ~~"unless the entity can demonstrate that~~"…or technically justify why such a study is not required~~"~~." The drafting team believes the timeframe associated with this requirement is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3 is unnecessary because notification of such a change may occur weeks or years prior to the change due to the ~~The SDT believes that specifying a single time frame for evaluation of the~~ wide variety of conditions that may be associated with a particular change ~~is not appropriate~~.~~-~~ Th~~is is because th~~e ~~SDT~~drafting team sees the entity initiating any change as having the incentive to move this along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date~~"~~,"as stipulated by Requirement R4, Part 4.2.

Requirement R1, Part 1.2 ~~requires~~directs the entity performing the Protection System Study to provide a summary of the study results to the affected ~~owners of Protection Systems applied at interconnected Facilities.~~Interconnected Element owner(s). As guidance, the ~~SDT~~drafting team lists the following inputs and results of a Protection

System Study that may be included in the summary provided pursuant to this requirement:

1. ~~Data used to determine fault currents in performing the study along with a listing of the single-line-to-ground and 3-phase fault currents for the bus or Element at the Interconnected Facility under study.~~
2. ~~2.~~1. A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the ~~Interconnected~~ Facility, and were reviewed for coordination of protective relays as part of the study including the contingencies used in the evaluation.
3. 2. Data used to determine Fault currents in performing the study, along with a listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Facility under study.
4. 3. A listing of any issues associated with the relay settings of the other owner(s) at the ~~Interconnected~~ Facility that were identified by the study.
5. 4. Any proposed revisions to a Protection System or its protective relay settings that were identified by the study.

Requirement R2:

The ~~SDT~~drafting team investigated various inputs that would trigger a review of the existing Protection System Studies~~,~~ and determined, through the experience of the ~~SDT~~drafting team members, along with informal surveys of several regional protection and control committees, that variations in ~~fault~~Fault currents of 10% or more are an appropriate indicator that an updated Protection System Study may be necessary. These variations could result from the accumulation of incremental changes over time. This requirement mandates a periodic review of ~~fault~~Fault currents and includes the calculation of the percent deviation between the ~~fault~~Fault current values used in the most recent Protection System Study and the present ~~fault~~Fault current values indicated by the short-~~-~~circuit study performed pursuant to this requirement. This calculation is necessary to identify ~~fault~~Fault current changes that must be communicated in accordance with Requirement R2, Part 2.~~3~~2.

Polling of ~~SDT~~drafting team membership and various protection engineering committees indicates that short-~~-~~circuit databases are customarily updated annually. Based on this information, the ~~SDT~~drafting team believes that requiring a 24-month periodic review of ~~fault~~Fault currents provides entities additional flexibility to schedule and perform these studies and calculate the percent deviation, as described in Requirement R2, Part 2.~~2~~1. The ~~SDT~~drafting team believes studies associated with changes that would affect the coordination in less than 24-~~-~~months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.2~~3~~ further directs the Transmission Owner to, within 30 calendar days, inform ~~interconnected~~ each owner of the Facility ~~owners~~associated with the Interconnected Element when short-~~-~~circuit studies indicate that 10% deviations in ~~fault~~Fault current have occurred at the ~~Interconnected Facility.~~interconnecting bus(s).

The ~~SDT~~drafting team believes the 30-day time frame associated with this requirement is reasonable for ~~sending notification~~providing the Fault current information to the interconnected entity(s) and is consistent with other NERC ~~Reliability Standards~~reliability standards.

In Requirement R2, the Transmission Owner is identified as the ~~functional entity~~Functional Entity responsible for performing the ~~fault~~Fault current studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.

Requirement R3:

This ~~requires the Interconnected Facility owners to evaluate the impact to their Protection Systems due to proposed changes by requiring~~directs the registered functional entity initiating ~~the changes~~any change to provide the details to the other affected entities of the Interconnected ~~Facility.~~Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes. Documentation provided to these other owners may include, but is not limited to~~:~~, power system configurations~~;~~, protection schemes~~;~~, schematics~~;~~, instrument transformer ratios~~;~~, type of relay(s~~);~~), communication equipment applied for protection~~;~~, and Protection System settings. The recipient will incorporate the applicable information into its Protection System Studies to evaluate whether changes are required.

The list of applicable changes provided in Requirement R3, Part 3.1 is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. The ~~SDT~~drafting team recognizes that ~~other~~ Facility changes ~~not directly associated with the interconnection~~at other locations can impact the Protection System Study of the Facility associated with the Interconnected ~~Facilities~~Element; e.g., the addition of a large autotransformer bank or generator not directly associated with the Interconnected ~~Facilities.~~Element. The ~~SDT~~drafting team believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the ~~SDT~~drafting team sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date~~"~~," as stipulated by Requirement R4, Part 4.2.

Requirement R3, Part 3.2 allows for entities to agree upon a schedule, appropriate to the circumstances, for providing the details needed to conduct a Protection System Study or, absent such agreement, within 30 days of a request for this information. This requirement provides a means for entities to receive requested information in a timely manner. In consideration of circumstances where the information may not be readily available or may be incomplete due the retirement of personnel, the purging of records, change of ownership, etc., it also provides the flexibility of mutually agreeing to a schedule for exchanging information. The ~~SDT~~drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide the requested information where no other agreement exists.

Additionally, this requirement includes a provision for providing details associated with changes to the previously agreed~~-~~upon coordination when~~: (1)~~ changes are made to Protection ~~System errors are found~~Systems during ~~misoperation~~Misoperation investigations, commissioning, ~~or~~ maintenance activities~~; (2)~~, or emergency replacements ~~are~~ made due to failures of Protection System components. Based upon the limited number of instances that would occur under such circumstances, the ~~SDT~~drafting team believes 30 calendar days after determining that changes are required is an appropriate time frame for providing the associated details to affected entities.

Requirement R4:

The reliability objective of this requirement is to bring the process of Protection System coordination full~~-~~ circle by gaining the confirmation of interconnected entities that their Protection Systems are coordinated consistent with the purpose of this standard. Cooperative participation of ~~Interconnected~~ Facility owners in communicating Protection System(s) design, and study results will achieve coordination of Protection Systems for reliable operation of the BES during Faults.

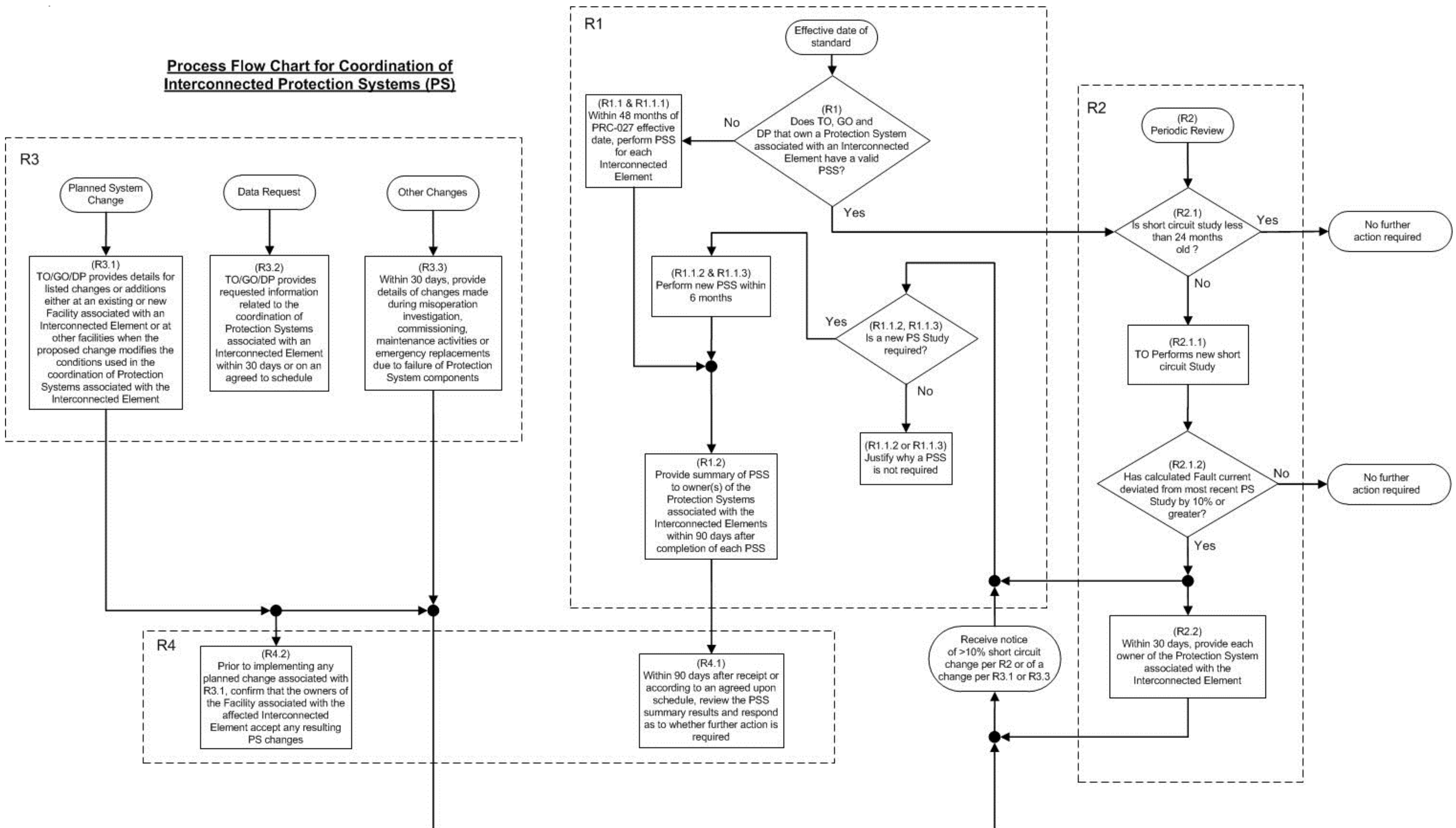
Requirement R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to ~~confirm agreement with~~review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2~~,~~; or absent ~~such agreement,~~acceptance propose revisions to achieve acceptable results. The ~~SDT~~drafting team believes 90 calendar days after receipt of the results of a Protection System Study provides a reasonable time for the owners of ~~Interconnected~~ Facilities to resolve differences and ~~reach agreement~~confirm acceptance that their Protection Systems are coordinated.

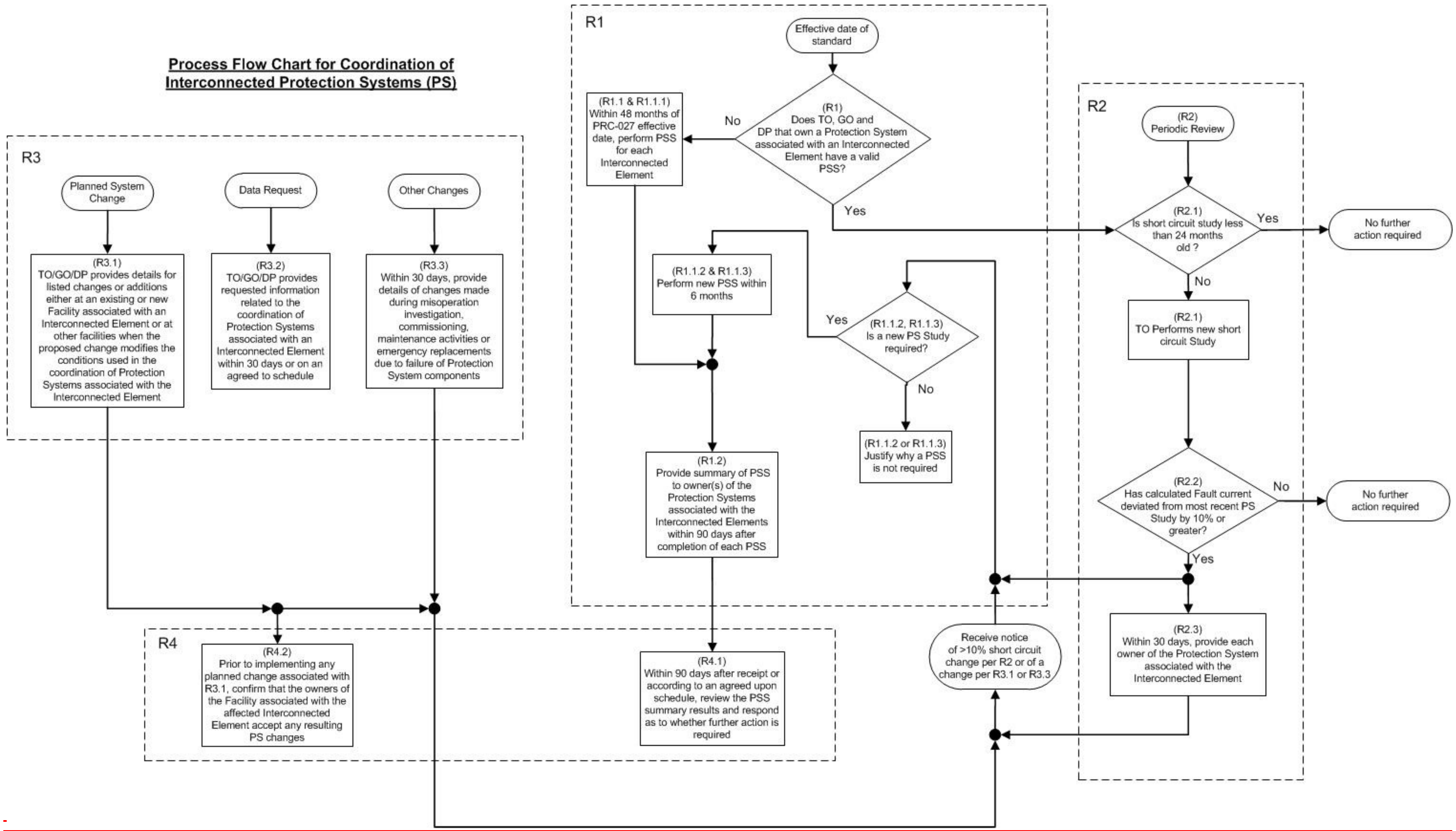
Requirement R4, Part 4.2 directs entities to confirm that planned changes described in Requirement 3.1 are acceptable prior to the in-service date of those changes. The purpose of this requirement is to assure the effects that planned changes have on Protection Systems at a Facility associated with the affected Interconnected ~~Facilities~~Element have been considered by all affected entities.

~~Requirement R4, Parts 4.3.1 and 4.3.2 direct confirmation within 30 calendar days that changes are acceptable when corrections are made due to Protection System errors found during misoperation investigations, commissioning, or maintenance activities, or when emergency replacements are made due to failures of Protection System components. Based upon the limited number of instances that would occur under such circumstances, the SDT believes 30 calendar days provides adequate time for achieving such agreement.~~

Process Flow Chart

: Below is a complete representation of the process, including the relationships between requirements:




Process Flow Chart for Coordination of Interconnected Protection Systems (PS)
R1
Effective date of standard
(R1) Does TO, GO and DP that own a Protection System associated with an Interconnected Element have a valid PSS?
No
Yes
(R1.1 & R1.1.1) Within 48 months of PRC-027 effective date, perform PSS for each Interconnected Element
(R1.1.2 & R1.1.3) Perform new PSS within 6 months
Yes
(R1.1.2, R1.1.3) Is a new PS Study required?
No
(R1.1.2 or R1.1.3) Justify why a PSS is not required
(R1.2) Provide summary of PSS to owner(s) of the Protection Systems associated with the Interconnected Elements within 90 days after completion of each PSS
R2
(R2) Periodic Review
(R2.1) Is short circuit study less than 24 months old ?
Yes
No further action required
No
(R2.1) TO Performs new short circuit Study
(R2.2) Has calculated Fault current deviated from most recent PS Study by 10% or greater?
No
No further action required
Yes
(R2.3) Within 30 days, provide each owner of the Protection System associated with the Interconnected Element
Receive notice of >10% short circuit change per R2 or of a change per R3.1 or R3.3
R3
Planned System Change
Data Request
Other Changes
(R3.1) TO/GO/DP provides details for listed changes or additions either at an existing or new Facility associated with an Interconnected Element or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element
(R3.2) TO/GO/DP provides requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 days or on an agreed to schedule
(R3.3) Within 30 days, provide details of changes made during misoperation investigation, commissioning, maintenance activities or emergency replacements due to failure of Protection System components
R4
(R4.2) Prior to implementing any planned change associated with R3.1, confirm that the owners of the Facility associated with the affected Interconnected Element accept any resulting PS changes
(R4.1) Within 90 days after receipt or according to an agreed upon schedule, review the PSS summary results and respond as to whether further action is required

Example Process

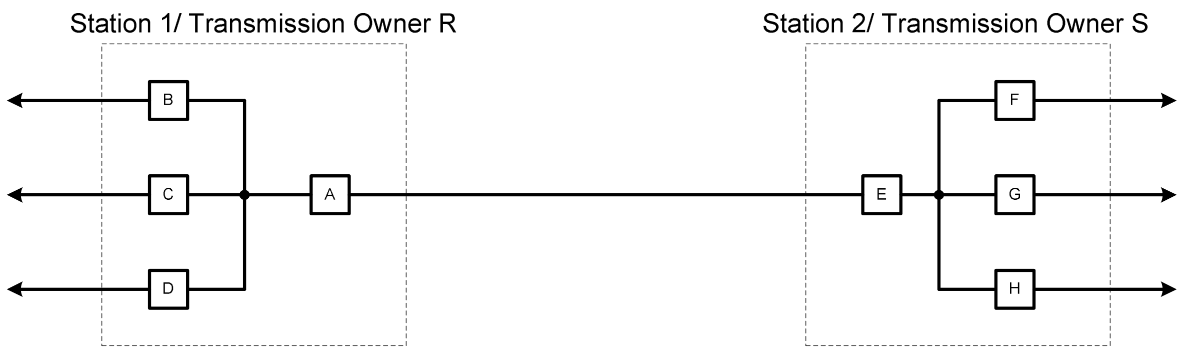
An example of the interaction between entities required to gather the information to perform an accurate study is below.

- The initiating entity (Entity A) will contact the interconnected entity (Entity B) and request up-to-date Protection System information.
- Upon receipt of the above request for information, Entity B will provide the information within 30 calendar days, or an agreed upon time frame.
- Entity A will perform a Protection System Study using the information received.
- Entity A will provide a summary of the results of the study to Entity B within 90 calendar days of completing the Protection System Study.
- Entity B will review the summary information and, within 90 calendar days of receiving the study results from Entity A, confirm agreement that coordination is achieved.
    - In cases where the study reveals that changes to Protection Systems are needed, Entity B would propose to Entity A revisions that achieve acceptable results.
- Documentation of the final agreement is required prior to implementation of planned changes.

Diagrams

Introduction: The diagrams below are intended to provide guidance related to the ~~responsibilities associated with the~~ purpose of this ~~Standard~~standard between owners of Facilities associated with the affected Interconnected ~~Facilities.~~Element. After the reviews and prior to implementation of the changes, the owners must reach agreement on the final settings to achieve coordination of the Protection Systems.

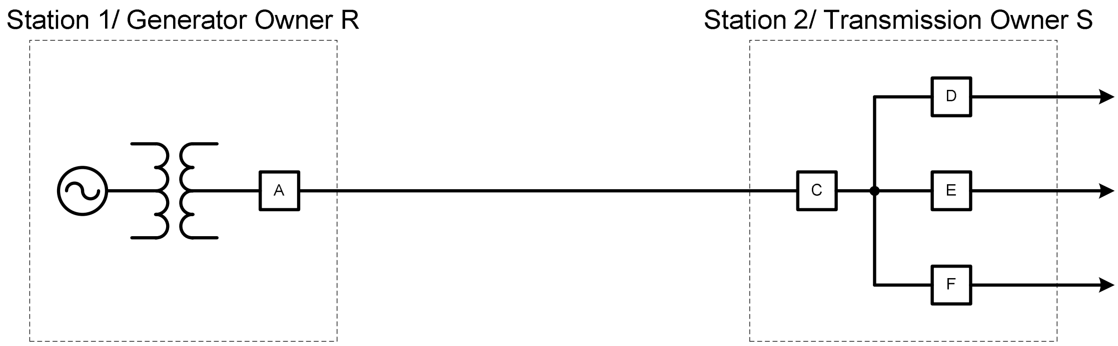
Figure 1



In Figure 1 above, the ~~interconnecting~~ Interconnected Element between the Transmission ~~Interconnected Facilities (Station 1 – Transmission Owner R and Station 2 – Transmission Owner S)~~Owners is the transmission line between Breakers A and E.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 1, ~~the responsibility for~~ Owner S is to ~~verify that~~review the Protection System settings associated with Breaker A (provided by Owner R) ~~do not result in~~for coordination issues with the Protection System settings associated with Breakers E, F, G, and H. Likewise, ~~the responsibility for~~ Owner R is to ~~verify that~~review the Protection System settings associated with Breaker E (provided by Owner S) ~~do not result in~~for coordination issues with the Protection System settings associated with Breakers A, B, C, and D.

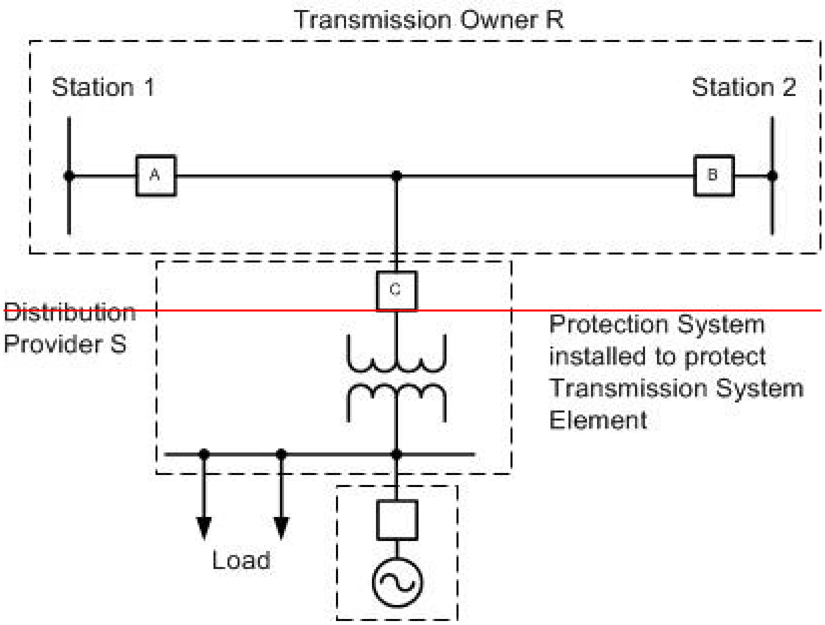
Figure 2

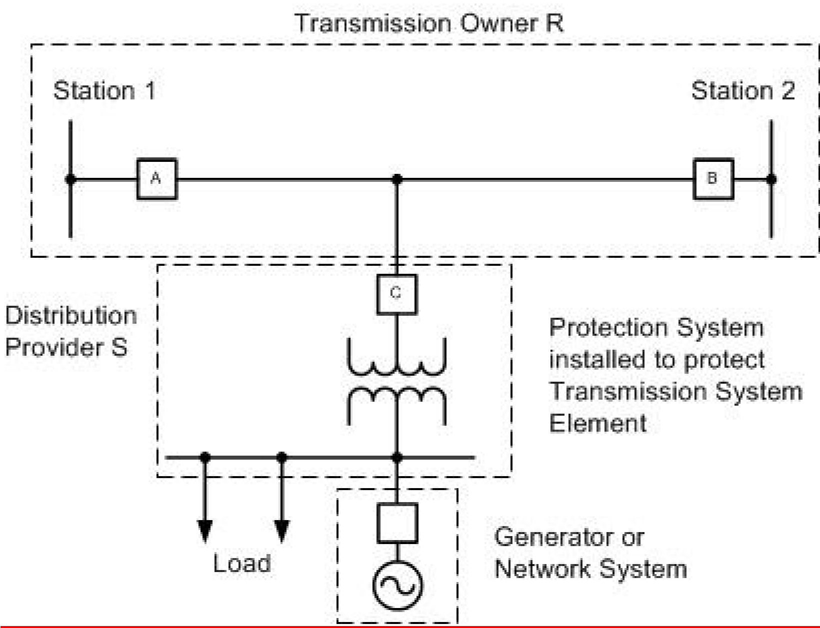


In Figure 2 above, the ~~interconnecting~~ Interconnected Element between the Transmission ~~to Generation Interconnected Facilities (Station 1 – Generation~~ Owner ~~R~~ and ~~Station 2 – Transmission~~the Generator Owner ~~S)~~ is the transmission line or bus between Breakers A and C.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 2, ~~the responsibility for~~ Transmission Owner S is to ~~verify that~~review the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems ~~do not result in~~for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, ~~the responsibility for~~ Generation Owner R is to ~~verify that~~review the Protection System settings associated with Breaker C (provided by Owner S) ~~do not result in~~for coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

Figure 3





In Figure 3 above, the ~~interconnecting~~ Interconnected Element between the Transmission Owner ~~to~~and the Distribution Provider ~~(with a generator) Interconnected Facilities (Transmission Owner R line between Breakers A and B – Distribution Provider S)~~ is the transmission line or tap between the line and Breaker C.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 3, ~~the responsibility for~~ Transmission Owner R is to ~~verify that~~review the Protection System settings associated with Line Breaker C (provided by Distribution Provider S) ~~and the generator Protection Systems do not result in~~for coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2. ~~Likewise, the responsibility for Distribution Provider S is to verify that the Protection System~~

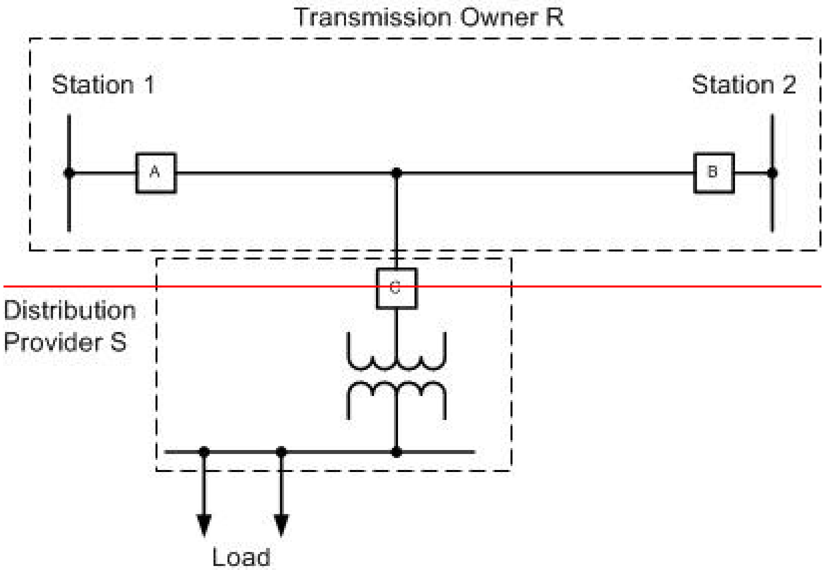
~~settings associated with Breakers A and B (provided by Owner R) do not result in coordination issues with the Protection System settings associated with Breaker C and the generator Protection Systems. In order to perform this verification, it will be necessary that the Generator Owner provide Distribution Provider S with its generator Protection System settings.~~

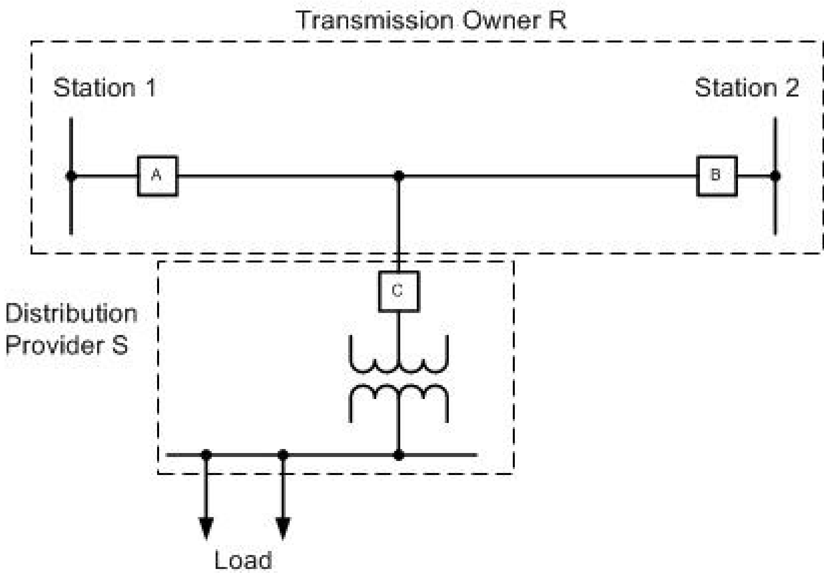
~~Note:~~ Notes:

A Protection System Study is required per this ~~Standard~~standard for this example if a Protection System at the Distribution Provider's substation is designed to ~~protect BES transmission system Elements~~detect Faults on the BES Transmission System.

"Protection Systems installed to detect faults on the BES Transmission System" are not inclusive of those relays that may operate for such faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.). As an example, reverse power relays are often installed to detect situations where the transmission source becomes de-energized and the distribution bank remains energized from a source on the low-voltage side of the transformer and the settings are calculated based on the charging current of the transformer from the low-voltage side. Although these relays may operate as a result of a Fault on a BES Element, they are not "installed to detect faults on the BES Transmission System."

Figure 4



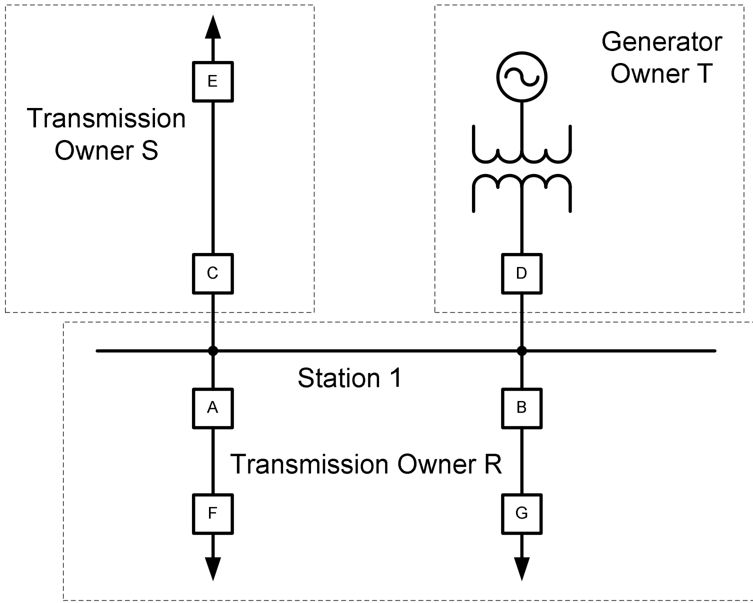


In Figure 4 above, the ~~interconnecting~~ Interconnected Element between the Transmission Owner ~~to~~and the Distribution Provider ~~Interconnected Facilities (Transmission Owner R line between Breakers A and B – Distribution Provider S)~~ is the transmission line or tap between the line and Breaker C.

Note: No specific Protection System Study is required per this ~~Standard~~standard for this example since the Protection System at the Distribution Provider's substation is not designed to protect BES transmission system Elements.

Figure 5

Transmission/Generation Facility with Multiple Owners



In Figure 5 above, the ~~interconnecting~~Interconnected Element between the Transmission Owners R and S and the Generation Owner T is the common Transmission bus. In this example, Transmission Owner S and Generator Owner T are not directly interconnected to each other at Transmission Station 1, and all direct interconnections are between Owner R and each of the other Owners connected to the bus.

Example: For the purposes of conducting the Protection System Study associated with the Facilities in Figure 5:

~~The responsibility for~~ Owner R is to ~~verify that~~review the Protection System settings associated with Breaker C, E, D, and the generator Protection System (provided by Owners S or T) ~~do not result in~~for coordination issues with the Protection System settings associated with Breakers A, B.

~~The responsibility for~~ Owner S is to ~~verify that~~review the Protection System settings associated with Breakers A, F, B, G, D, and the generator Protection System (provided by Owners R or T) ~~do not result in~~for coordination issues with the Protection System settings associated with Breaker C. To perform this ~~verification~~review, it will be necessary that Transmission Owner R provide Owner S with its settings for Breakers A, F, B, and G, as well as the settings for Breaker D and generator Protection System settings provided to Owner R by Generator Owner T.

~~The responsibility for~~ Owner T is to ~~verify that~~review the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R or S) ~~do not result in~~for coordination issues with the Protection System settings associated with Breaker D or the Protection Systems associated with generator Protection Systems. In order to perform this ~~verification~~review, it will be necessary that Transmission Owner R provide Generator Owner T with its settings for Breakers A, F, G, and B, as well as the settings for Breaker C and E provided to Owner R by Transmission Owner S.

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Project 2007-06 System Protection Coordination

Unofficial Comment Form
2nd Draft of PRC-027-1: Protection System Coordination for Performance During Faults

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the 2nd draft of the standard for Protection System Coordination for Performance During Faults. Comments must be submitted by 8 p.m. Eastern **December 17, 2012**. If you have questions please contact Al McMeekin at al.mcmeekin@nerc.net or by telephone at 803-530-1963.

http://www.nerc.com/filez/standards/System_Protection_Project_2007-06.html

Background Information:
The Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted an initial draft of the Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPCSDT attempted to address the planning and non-operational issues identified in the assessment of PRC-001-1 performed by the NERC System Protection and Control Task Force (SPCTF) as well as the operating time frame issues identified in FERC Order 693. These operating time frame requirements involved detecting Protection System failures, informing operators and taking quick corrective actions; consequently, the SPCSDT transferred the Order 693 directives associated with Requirements R2, R5 and R6 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standards associated within that project. Additionally, the SPCSDT determined that the training aspects of PRC-001-1 Requirement R1 are more appropriately addressed by Reliability Standard PER-005-1 with revision to its Applicability section to include the Generator Operator. Therefore, PRC-001-3 was created to retain Requirement R1 only, as identified in the implementation plan for PRC-027-1. The two remaining requirements, Requirements R3 and R4 of PRC-001-1 address the coordination of new and existing protective systems. These aspects of coordination are incorporated in the proposed standard PRC-027-1 Protection System Coordination for Performance During Faults.

Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012. The SPCSDT has responded to stakeholder comments and incorporated pertinent suggestions into the standard. The SPCSDT is presenting the second draft of PRC-027-1 for stakeholder review and comment.

For questions 1-5, please provide specific comments related to the individual question.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Based on stakeholder comments, the drafting team modified the Purpose of this standard to "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults." Do you agree with this Purpose? If not, please provide specific suggestions for change in the comment area.

   ☐ Yes

   ☐ No

   Comments:

2. The drafting team is proposing two definitions for use only with PRC-027-1 as follows:

   Interconnected Element: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity

   Protection System Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.

   Do you agree with these definitions, if not please provide specific suggestions for change in the comment area.

   ☐ Yes

   ☐ No

   Comments:

3. In Requirement R1, the drafting team modified the time frame to allow entities 48 months to have a documented Protection System Study completed for each Interconnected Element if no Protection System Study exists. Note, the drafting team has allowed inclusion of all previously performed Protection System Studies whose summary of results include, at a minimum, the protective relay settings reviewed, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.

   ☐ Yes

   ☐ No

   Comments:

4. In Requirement R4, the drafting team replaced the need to ‘reach agreement’ with ‘confirming acceptance.’

   Do you agree with this change? If not, please provide specific suggestions for change in the comment area.

   ☐ Yes

   ☐ No

   Comments:

5. The requirements and associated measures were modified to indicate that information was ‘provided’ instead of ‘demonstrating that each affected entity received notification.’ Do you agree with this change? If not, please provide specific suggestions for change in the comment area.

   ☐ Yes

   ☐ No

   Comments:

Project 2007-06 System Protection Coordination Mapping Document

Mapping Document Showing Translation of PRC-001-2 – System Protection Coordination to PRC-027-1 – Protection System Coordination for Performance During Faults

Updated 10-31 to reflect changes made to requirements

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	Retained	NA
R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R2.1** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.	PRC-027-1, R1, R3, & R4 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Study for each Interconnected Element on its System as follows: **1.1.3.** According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 or Part 3.3, or technically justify why such a study is not required.

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
R2.2 Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.		**1.2.** Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed). **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnected Element: **3.1.** Details for any change or additions listed below; either at an existing or new Facility associated with the Interconnected Element; or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s). • New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios • Changes to a transmission system Element that change any sequence or mutual coupling impedance • Changes to generator unit(s) that result in a change in impedance

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		• Changes to the generator step-up transformer(s) that result in a change in impedance **3.2.** Requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 calendar days of receiving a request or according to an agreed-upon schedule. **3.3.** Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **4.2.** Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.
R3. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing	PRC-027-1, R1, R2, R3, & R4 Note: Applicability	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Study for each Interconnected Element on its System as follows: **1.1.1.** Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
Authorities.	changed to GO, TO and DP	Element exists. **1.1.2.** Within six calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. **1.2.** Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed). **R2.** For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall: **2.1.** At least once every 24 months: **2.1.1** Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1. **2.1.2.** Calculate the percent deviation between the Fault current values (single line to ground and 3-phase for the interconnecting bus(s) under

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		consideration) used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1.1, using the following equation: Where: I_{scs} = Fault current value from present short-circuit study And: I_{pss} = Fault current value used in the most recent Protection System Study **2.2.** Within 30 calendar days after identification where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates a deviation in Fault current of 10% or greater, provide each owner of the Protection System associated with the Interconnected Element the updated Fault current values (Iscs). **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Responsible Entity connected to the same Interconnected Element: **3.2.** Requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 calendar days of receiving a request or according to an agreed-upon schedule. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		shall: **4.1.** Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.

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Implementation Plan

Project 2007-06 System Protection Coordination
PRC-027-1

Approvals Requested

- PRC-027-1 Protection System Coordination for Performance During Faults
- PRC-001-3 System Protection Coordination

Applicable Entities

Standard	Applicable Entities					
	TO	GO	DP	TOP	GOP	BA
PRC-027-1: Protection System Coordination for Performance During Faults	X	X	X			
PRC-001-3: System Protection Coordination				X	X	X

Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definitions for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

Interconnected Element: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.

Protection System Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.

Background

On December 7, 2006, the NERC Planning Committee approved the assessment of Standard PRC-001-1 (System Protection Coordination) prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF asserted:

> *"The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the 'operating horizon, operations planning horizon, and planning horizon' protection coordination issues, the deficiencies in the current standard are magnified."*

And further:

> *"The SPCTF… recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards."*

The Standard Committee approved the Standard Authorization Request with modifications by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

With the development of the proposed Reliability Standard PRC-027-1, the Standard Drafting Team (SDT) for Project 2007-06 – System Protection Coordination, has followed the observations and recommendation of the NERC SPCTF assessment of PRC-001-1 which had six requirements. The SDT accomplishes this by:

1. Incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) and moving those requirements into a new standard (as recommended by the SPCTF assessment), focusing on the performance of Protection Systems during Faults.
2. Assigning responsibility for coordination of Protection Systems during Faults to the appropriate functional entities – the Protection System equipment owners, specifically: Transmission Owners, Generator Owners, and Distribution Providers.
3. Transferring the responsibility of addressing the three operating horizon Requirements R2, R5, and R6 of PRC-001-1 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standard(s) within that project. (The NERC Board of Trustees approved these changes proposed by the Project 2007-03 team when it approved PRC-001-2 on May 9, 2012.)
4. Leaving the legacy Requirement R1 of PRC-001-2 in PRC-001-3 (thereby not creating a reliability gap) until it is incorporated into a new or revised reliability standard.

Effective Date of New or Revised Standards and Definitions

PRC-027-1 - Protection System Coordination for Performance During Faults

PRC-027-1 shall become effective on the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. For Interconnected Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.

PRC-001-3 – System Protection Coordination

Same effective date as PRC-027-1.

Effective Date for Definitions

The two proposed definitions (Interconnected Facilities and Protection System Study) shall become effective at the same time as PRC-027-1.

Retirement:

PRC-001-2 – Protection System Coordination shall be retired at midnight the day before PRC-001-3 becomes effective.

Implementation Plan

Project 2007-06 System Protection Coordination
PRC-027-1

Approvals Requested

- PRC-027-1 Protection System Coordination for Performance During Faults
- PRC-001-3 System Protection Coordination

Applicable Entities

Standard	Applicable Entities					
	TO	GO	DP	TOP	GOP	BA
PRC-027-1: Protection System Coordination for Performance During Faults	X	X	X			
PRC-001-3: System Protection Coordination				X	X	X

Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definitions for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

Interconnected ~~Facilities~~Element: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity~~BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities~~.

Protection System Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.

Background

On December 7, 2006, the NERC Planning Committee approved the assessment of Standard PRC-001-1 (System Protection Coordination) prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF asserted:

> *"The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In*

addressing the 'operating horizon, operations planning horizon, and planning horizon' protection coordination issues, the deficiencies in the current standard are magnified."

And further:

"The SPCTF… recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards."

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With the development of the proposed Reliability Standard PRC-027-1, the Standard Drafting Team (SDT) for Project 2007-06 – System Protection Coordination, has followed the observations and recommendation of the NERC SPCTF assessment of PRC-001-1 which had six requirements. The SDT accomplishes this by:

1. Incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) and moving those requirements into a new standard (as recommended by the SPCTF assessment), focusing on the performance of Protection Systems during Faults.
2. Assigning responsibility for coordination of Protection Systems during Faults to the appropriate functional entities – the Protection System equipment owners, specifically: Transmission Owners, Generator Owners, and Distribution Providers.
3. Transferring the responsibility of addressing the three operating horizon Requirements R2, R5, and R6 of PRC-001-1 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standard(s) within that project. (The NERC Board of Trustees approved these changes proposed by the Project 2007-03 team when it approved PRC-001-2 on May 9, 2012.)
4. Leaving the legacy Requirement R1 of PRC-001-2 in PRC-001-3 (thereby not creating a reliability gap) until it is incorporated into a new or revised reliability standard.

Effective Date of New or Revised Standards and Definitions

PRC-027-1 - Protection System Coordination for Performance During Faults

PRC-027-1 shall become effective on the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. ~~on the first day of the first calendar quarter that is three months beyond the date that this standard is approved by applicable regulatory authorities, where such explicit approval is required. Where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter that is three~~

~~months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise prescribed by the laws or regulations of the applicable ERO governmental authorities.~~ For ~~Facility Interconnections~~ Interconnected Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.

PRC-001-3 – System Protection Coordination
Same effective date as PRC-027-1.

Effective Date for Definitions

The two proposed definitions (Interconnected Facilities and Protection System Study) shall become effective at the same time as PRC-027-1.

Retirement:

PRC-001-2 – Protection System Coordination shall be retired at midnight the day before PRC-001-3 becomes effective.

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Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 — Protection System Coordination for Performance During Faults

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1 — Protection System Coordination for Performance During Faults.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

The System Protection Coordination Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric

System; or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures; nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and, therefore, concentrated its approach on the reliability impact of the requirements.

PRC-027-1 Protection System Coordination for Performance During Faults is a new Reliability Standard with the stated purpose: "*To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.*" PRC-027-1 has four (4) requirements that incorporate and enhance the reliability intent of Requirements R3 and R4 of PRC-001-1. The new standard addresses the aspects of coordination for new Protection Systems, as well as changes to existing Protection Systems. The new requirements describe the steps necessary to achieve coordination. The coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner, and confirming acceptance of Protection System settings and schemes.

All four requirements are assigned VRFs of Medium. The assignment of the Medium VRFs was made based on the premise that failure to perform these coordination activities by themselves would not directly cause or contribute to bulk power system instability, separation, or a Cascading sequence of failures. For a requirement to be assigned a "High" VRF, there should be the expectation that failure to meet the required performance "will" result in instability, separation, or Cascading failures, and this is usually not the case when an applicable entity fails to 'coordinate' activities. While the SDT agrees that, under some circumstances, it is possible that a failure to perform the required activities may hinder the coordination process; however, the failure would not, by itself, result in instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-027-1, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to perform a Protection System Study for each Interconnected Element to verify that Protection Systems coordinate such that the least number of power system Elements are isolated to clear Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R1 is similar in scope to Requirements R2, R3 and R4, as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R1 directs that Protection System Studies are performed for every Interconnected Element to verify coordination of existing Protection Systems. This requirement is similar to Requirement R1 of FAC-002-1, which also requires studies be performed and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to perform a Protection System Study for each Interconnected Facility to verify that Protection Systems coordinate such that the least number of power system Elements are isolated to clear Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R1 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed a Protection System Study on an Interconnected Element per R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Study at an interconnecting bus per R1, Part 1.1.2, or documented why a study was not required but was late by less than or equal to 30 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by 10 calendar days or less.	The responsible entity performed a Protection System Study on an Interconnected Element per R1, Part 1.1.1, but was late by more than 30 calendar days. OR The responsible entity performed a Protection System Study at an interconnecting bus per R1, Part 1.1.2, or documented why a study was not required but was late by more than 30 calendar days but less than or equal to 40 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity performed a Protection System Study at an interconnecting bus per R1, Part 1.1.2, or documented why a study was not required but was late by more than 40 calendar days but less than or equal to 50 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity performed a Protection System Study at an interconnecting bus per R1, Part 1.1.2, or documented why a study was not required but was late by more than 50 calendar days. OR The responsible entity provided the Protection System Study results in accordance with R1, Part 1.2, but was late by more than 30 calendar days. OR The responsible entity failed to perform a Protection System Study on an Interconnected Element per R1, Parts 1.1.1, 1.1.2, or 1.1.3, or document why a study was not required. OR The responsible entity failed to provide Protection System Study results in accordance with R1, Part 1.2.

VSL Justifications – PRC-027-1, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to periodically review, calculate the percent deviation in fault current values used as inputs for updating Protection System Study(s), and to provide each owner of the Protection System associated with the Interconnected Element of requisite deviations in fault currents, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R2 is similar in scope to Requirements R1, R3 and R4, as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R2 facilitates a periodic review of Fault currents and notification of owner(s) of the Protection System(s) associated with the Interconnected Element(s). This requirement is similar to Requirement R6 of BAL-005-0.2b in that it also requires the comparison of calculated data and possible notification of other entities; and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to periodically review, calculate the percent deviation in fault current values used as inputs for updating Protection System Study(s) and to provide each owner of the Protection System associated with the Interconnected Element of requisite deviations in fault currents, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R2 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by less than or equal to 30 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element of the changes in Fault currents, as described in R2, Part 2.2, but was late by less than or equal to 10 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 40 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element of the changes in Fault currents, as described in R2, Part 2.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 40 calendar days but less than or equal to 50 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element of the changes in Fault currents, as described in R2, Part 2.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Transmission Owner performed a short circuit study as described in R2, Part 2.1, but was late by more than 50 calendar days. OR The Transmission Owner failed to perform a short circuit study, as described in R2, Part 2.1. OR The Transmission Owner failed to calculate the percent deviation between the Fault currents according to the formula designated in R2, Part 2.2. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element of the changes in Fault currents, as described in R2, Part 2.2, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnected Element the changes in Fault currents.

VSL Justifications – PRC-027-1, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to communicate proposed changes that modify the conditions used in the coordination of Protection Systems associated with an Interconnected Element could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R3 is similar in scope to Requirements R1, R2 and R4 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R3 facilitates the provision of pertinent information regarding proposed changes that could impact the coordination of Protection Systems associated with an Interconnected Element. This requirement is similar to Requirement R2 of FAC-009-1 in that it also requires the provision of reliability data to other pertinent functional entities, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to communicate proposed changes that modify the conditions used in the coordination of Protection Systems associated with an Interconnected Element could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R3 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R3			
Lower	**Moderate**	**High**	**Severe**
The responsible entity provided the requested information per R3, Part 3.2, but was late by 10 calendar days or less. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by 10 calendar days or less.	The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity failed to provide information to the owner(s) of the Facility associated with the Interconnected Element for any proposed change identified in R3.1. OR The responsible entity provided the requested information per R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the required information identified in R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the requested information.

VSL Justifications – PRC-027-1, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to confirm acceptance for proposed changes that modify the conditions used in the coordination of Protection System(s) associated with the Interconnected Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R4 is similar in scope to Requirements R1, R2 and R3 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R4 mandates responsible entities confirm acceptance on Protection System Study results or proposed changes to Protection System(s) prior to implementation. This requirement is similar to Requirement R2 of PRC-023-1 in that it also requires agreement be obtained, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to confirm acceptance for proposed changes that modify the conditions used in the coordination of Protection System(s) associated with the Interconnected Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R4 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity confirmed acceptance of the summary results of the Protection System Study per R4, Part 4.1, but was late by 10 calendar days or less.	The responsible entity confirmed acceptance of the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity confirmed acceptance of the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity confirmed acceptance of the summary results of the Protection System Study per R4, Part 4.1, but was late by more than 30 calendar days. OR The responsible entity failed to confirm acceptance of the summary results of the Protection System Study per R4, Part 4.1. OR The responsible entity failed to confirm acceptance of the planned changes pursuant to R4, Part 4.2, prior to implementation of those changes.

VSL Justifications – PRC-027-1, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Standards Announcement

Project 2007-06 System Protection Coordination

Successive Ballot and Non-Binding Poll is now open through Monday, December 17, 2012

Now Available

A successive ballot of **PRC-027-1** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels (VRFs and VSLs) is now open through **8 p.m. Eastern on Monday, December 17, 2012.**

Instructions
Members of the ballot pools associated with this project may log in and submit their vote for the Standard and opinion in the non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Background
The Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted an initial draft of the Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPCSDT attempted to address the planning and non-operational issues identified in the assessment of PRC-001-1 performed by the NERC System Protection and Control Task Force (SPCTF) as well as the operating time frame issues identified in FERC Order 693. These operating time frame requirements involved detecting Protection System failures, informing operators and taking quick corrective actions; consequently, the SPCSDT transferred the Order 693 directives associated with Requirements R2, R5 and R6 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standards associated within that project. Additionally, the SPCSDT determined that Requirement R1 in PRC-001-1 (a requirement for the Transmission Operator, Balancing Authority and Generator Operator to "be familiar with the purpose and limitations of protection system schemes applied in its area") is unrelated to coordination of protection systems and belongs in another project. Therefore, PRC-001-3 will retain Requirement R1 only, as identified in the implementation plan for PRC-027-1. The two remaining requirements, Requirements R3 and R4 of PRC-001-1 address the coordination of new and existing protection systems. These aspects of coordination are incorporated in the proposed standard PRC-027-1 Protection System Coordination for Performance During Faults.

Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012. The SPCSDT has responded to stakeholder comments and incorporated pertinent suggestions into the standard. The SPCSDT is presenting the second draft of PRC-027-1 for stakeholder review and comment.

For additional information please see the project page.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-06 System Protection Coordination

Formal Comment Period Open: November 16, 2012 – December 17, 2012

Upcoming:
Successive Ballot and Non-Binding Poll: December 7-17, 2012

Now Available

A formal comment period for **PRC-027-1 – Protection System Coordination for Performance During Faults** is open through 8 p.m. Eastern on **Monday, December 17, 2012**.

A successive ballot of **PRC-027-1** and a non-binding poll of the associated VRFs and VSLs will be conducted beginning on **Friday, December 7, 2012 through 8 p.m. Eastern on Monday, December 17, 2012.**

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, December 17, 2012**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the Standard and opinion in the non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps

A successive ballot of **PRC-027-1** and a non-binding poll of the associated VRFs and VSLs will be conducted beginning on **Friday, December 7, 2012 through 8 p.m. Eastern on Monday, December 17, 2012.**

Background

The Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted an initial draft of the Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPCSDT attempted to address the planning and non-operational issues identified in the assessment of PRC-001-1 performed by the NERC System Protection and Control Task Force (SPCTF) as well as the operating time frame issues identified in FERC Order 693. These operating time frame requirements involved detecting Protection System failures, informing operators and taking quick corrective actions;

consequently, the SPCSDT transferred the Order 693 directives associated with Requirements R2, R5 and R6 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standards associated within that project. Additionally, the SPCSDT determined that Requirement R1 in PRC-001-1 (a requirement for the Transmission Operator, Balancing Authority and Generator Operator to "be familiar with the purpose and limitations of protection system schemes applied in its area") is unrelated to coordination of protection systems and belongs in another project. Therefore, PRC-001-3 will retain Requirement R1 only, as identified in the implementation plan for PRC-027-1. The two remaining requirements, Requirements R3 and R4 of PRC-001-1 address the coordination of new and existing protection systems. These aspects of coordination are incorporated in the proposed standard PRC-027-1 Protection System Coordination for Performance During Faults.

Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012. The SPCSDT has responded to stakeholder comments and incorporated pertinent suggestions into the standard. The SPCSDT is presenting the second draft of PRC-027-1 for stakeholder review and comment.

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Standards Announcement

Project 2007-06 System Protection Coordination

Formal Comment Period Open: November 16, 2012 – December 17, 2012

Upcoming:
Successive Ballot and Non-Binding Poll: December 7-17, 2012

Now Available

A formal comment period for **PRC-027-1 – Protection System Coordination for Performance During Faults** is open through 8 p.m. Eastern on **Monday, December 17, 2012**.

A successive ballot of **PRC-027-1** and a non-binding poll of the associated VRFs and VSLs will be conducted beginning on **Friday, December 7, 2012 through 8 p.m. Eastern on Monday, December 17, 2012.**

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, December 17, 2012**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the Standard and opinion in the non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps

A successive ballot of **PRC-027-1** and a non-binding poll of the associated VRFs and VSLs will be conducted beginning on **Friday, December 7, 2012 through 8 p.m. Eastern on Monday, December 17, 2012.**

Background

The Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted an initial draft of the Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPCSDT attempted to address the planning and non-operational issues identified in the assessment of PRC-001-1 performed by the NERC System Protection and Control Task Force (SPCTF) as well as the operating time frame issues identified in FERC Order 693. These operating time frame requirements involved detecting Protection System failures, informing operators and taking quick corrective actions;

consequently, the SPCSDT transferred the Order 693 directives associated with Requirements R2, R5 and R6 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standards associated within that project. Additionally, the SPCSDT determined that Requirement R1 in PRC-001-1 (a requirement for the Transmission Operator, Balancing Authority and Generator Operator to "be familiar with the purpose and limitations of protection system schemes applied in its area") is unrelated to coordination of protection systems and belongs in another project. Therefore, PRC-001-3 will retain Requirement R1 only, as identified in the implementation plan for PRC-027-1. The two remaining requirements, Requirements R3 and R4 of PRC-001-1 address the coordination of new and existing protection systems. These aspects of coordination are incorporated in the proposed standard PRC-027-1 Protection System Coordination for Performance During Faults.

Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012. The SPCSDT has responded to stakeholder comments and incorporated pertinent suggestions into the standard. The SPCSDT is presenting the second draft of PRC-027-1 for stakeholder review and comment.

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Standards Announcement

Project 2007-06 System Protection Coordination

Successive Ballot and Non-Binding Poll Results

Now Available

A successive ballot for **PRC-027-1** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels (VRFs and VSLs) concluded at **8 p.m. Eastern on Monday, December 17, 2012.**

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results.

Approval	Non-binding Poll Results
Quorum: 76.47% Approval: 33.23%	Quorum: 75.58% Supportive Opinions: 34.80%

Next Steps

The drafting team will consider all comments received during the formal comment period to determine the next steps.

Background

The Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted an initial draft of the Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPCSDT attempted to address the planning and non-operational issues identified in the assessment of PRC-001-1 performed by the NERC System Protection and Control Task Force (SPCTF) as well as the operating time frame issues identified in FERC Order 693. These operating time frame requirements involved detecting Protection System failures, informing operators and taking quick corrective actions; consequently, the SPCSDT transferred the Order 693 directives associated with Requirements R2, R5 and R6 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standards associated within that project. Additionally, the SPCSDT determined that Requirement R1 in PRC-001-1 (a requirement for the Transmission Operator, Balancing Authority and Generator Operator to "be familiar with the purpose and limitations of protection system schemes applied in its area") is unrelated to coordination of protection systems and belongs in another project. Therefore, PRC-001-3 will retain Requirement R1 only, as identified in the implementation plan for PRC-027-1. The two remaining requirements, Requirements R3 and R4 of PRC-001-1 address the coordination of new and existing protection systems. These aspects of coordination are incorporated in the proposed standard PRC-027-1 Protection System Coordination for Performance During Faults.

Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012. The SPCSDT has responded to stakeholder comments and incorporated pertinent suggestions into the standard. The SPCSDT is presenting the second draft of PRC-027-1 for stakeholder review and comment.

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The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Development Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2007-06 Successive Ballot PRC-027-1 November 2012_in
Ballot Period:	12/7/2012 - 12/17/2012
Ballot Type:	Successive
Total # Votes:	325
Total Ballot Pool:	425
Quorum:	**76.47 % The Quorum has been reached**
Weighted Segment Vote:	33.23 %
Ballot Results:	**The drafting team is reviewing comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	114	1	31	0.378	51	0.622	9	23
2 - Segment 2.	9	0.5	2	0.2	3	0.3	3	1
3 - Segment 3.	102	1	24	0.348	45	0.652	5	28
4 - Segment 4.	37	1	5	0.217	18	0.783	2	12
5 - Segment 5.	88	1	18	0.265	50	0.735	3	17
6 - Segment 6.	52	1	15	0.385	24	0.615	3	10
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	9	0.3	1	0.1	2	0.2	2	4
9 - Segment 9.	6	0.2	0	0	2	0.2	0	4
10 - Segment 10.	8	0.6	3	0.3	3	0.3	1	1
Totals	**425**	**6.6**	**99**	**2.193**	**198**	**4.407**	**28**	**100**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Negative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Negative	

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins		
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Pasadena	Marco A Sustaita	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	City Water, Light & Power of Springfield	Shaun Anders		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	Consumers Power Inc.	Stuart Sloan		
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba		
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	
1	Idaho Power Company	Molly Devine	Negative	
1	Imperial Irrigation District	Tino Zaragoza	Negative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	
1	JEA	Ted Hobson	Negative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Negative	
1	Lee County Electric Cooperative	John W Delucca	Negative	
1	LG&E Energy Transmission Services	Bradley C. Young		
1	Long Island Power Authority	Robert Ganley	Negative	
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Negative	
1	Metropolitan Water District of Southern California	Ernest Hahn		
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Negative	
1	New York Power Authority	Bruce Metruck	Negative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	

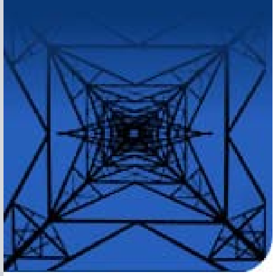
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber		
1	Omaha Public Power District	Doug Peterchuck	Negative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Negative	
1	PacifiCorp	Ryan Millard	Affirmative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Brett A. Koelsch	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	
1	South California Edison Company	Steven Mavis	Negative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry G Akens	Negative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Turlock Irrigation District	Esteban Martinez	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn	Negative	
1	Western Farmers Electric Coop.	Forrest Brock	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Denike		
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	ISO New England, Inc.	Kathleen Goodman	Abstain	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Negative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Alameda Municipal Power	Douglas Draeger	Negative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick		
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	
3	Basin Electric Power Cooperative	Daniel Klempel		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Bonneville Power Administration	Rebecca Berdahl		
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Negative	

3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Lodi, California	Elizabeth Kirkley	Negative	
3	City of Palo Alto	Eric R Scott	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Ukiah	Colin Murphey	Negative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Clearwater Power Co.	Dave Hagen		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Negative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Consumers Power Inc.	Roman Gillen		
3	Coos-Curry Electric Cooperative, Inc	Roger Meader		
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger	Affirmative	
3	Fall River Rural Electric Cooperative	Bryan Case		
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Negative	
3	JEA	Garry Baker	Negative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter		
3	Lane Electric Cooperative, Inc.	Rick Crinklaw		
3	Lincoln Electric System	Jason Fortik	Negative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Northern Lights Inc.	Jon Shelby		
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Negative	
3	Pacific Northwest Generating Cooperative	Rick Paschall		
3	PacifiCorp	Dan Zollner	Affirmative	
3	Pepco Holdings, Inc.	Mark R Jones	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		

3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Raft River Rural Electric Cooperative	Heber Carpenter		
3	Rutherford EMC	Thomas M Haire	Negative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salmon River Electric Cooperative	Ken Dizes	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Umatilla Electric Cooperative	Steve Eldrige		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	
4	Central Lincoln PUD	Shamus J Gamache	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	
4	Imperial Irrigation District	Diana U Torres	Negative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Pacific Northwest Generating Cooperative	Aleka K Scott		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Southern Minnesota Municipal Power Agency	Richard L Koch		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Turlock Irrigation District	Steven C Hill		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
4	WPPI Energy	Todd Komplin	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	

5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Negative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex		
5	CPS Energy	Robert Stevens	Negative	
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer		
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Negative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne	Negative	
5	Imperial Irrigation District	Marcela Y Caballero	Negative	
5	Invenergy LLC	Alan Beckham		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Negative	
5	New York Power Authority	Wayne Sipperly	Negative	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	
5	PacifiCorp	Sandra L. Shaffer		
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	

5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	WPPI Energy	Steven Leovy	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Abstain	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	
6	Constellation Energy Commodities Group	Donald Schopp	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz	Negative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Negative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen		
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II	Negative	



6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	
8		Roger C Zaklukiewicz		
8		James A Maenner	Abstain	
8		Edward C Stein		
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan		
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	California Energy Commission	William M Chamberlain		
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	
9	Oregon Public Utility Commission	Jerome Murray		
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Carter B Edge		
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Negative	

Legal and Privacy

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Account Log-In/Register

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A New Jersey Nonprofit Corporation

Non-binding Poll Results

Project 2007-06 PRC-027-1

Non-binding Results	
Non-binding Poll Name:	Project 2007-06 Non-binding Poll PRC-027-1
Poll Period:	12/7/2012 - 12/17/2012
Total # Opinions:	294
Total Ballot Pool:	389
Summary Results:	75.58% of those who registered to participate provided an opinion or an abstention; 34.80% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Negative	
1	Austin Energy	James Armke	Negative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins		
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Pasadena	Marco A Sustaita	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	City Water, Light & Power of Springfield	Shaun Anders		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	

1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba		
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis		
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	
1	Idaho Power Company	Molly Devine	Negative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Negative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Negative	
1	Lee County Electric Cooperative	John W Delucca	Negative	
1	LG&E Energy Transmission Services	Bradley C. Young		
1	Long Island Power Authority	Robert Ganley	Negative	
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Negative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber		

1	Omaha Public Power District	Doug Peterchuck	Negative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Negative	
1	PacifiCorp	Ryan Millard	Abstain	
1	PECO Energy	Ronald Schloendorn		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Brett A. Koelsch	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Negative	
1	South California Edison Company	Steven Mavis	Negative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Turlock Irrigation District	Esteban Martinez	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn	Negative	
1	Western Farmers Electric Coop.	Forrest Brock	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Denike		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	Midwest ISO, Inc.	Marie Knox	Negative	

2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon		
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Alameda Municipal Power	Douglas Draeger		
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick		
3	Basin Electric Power Cooperative	Daniel Klempel		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl		
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Negative	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Lodi, California	Elizabeth Kirkley	Affirmative	
3	City of Palo Alto	Eric R Scott	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Ukiah	Colin Murphey	Negative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Negative	
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Negative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Mace D Hunter		

3	Lincoln Electric System	Jason Fortik	Negative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Negative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Negative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salmon River Electric Cooperative	Ken Dizes	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	

4	Central Lincoln PUD	Shamus J Gamache	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Turlock Irrigation District	Steven C Hill		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
4	WPPI Energy	Todd Komplin	Negative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Phillip Porter		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	

5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Negative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex		
5	CPS Energy	Robert Stevens	Negative	
5	Detroit Edison Company	Christy Wicke		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer		
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Negative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky		
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne	Negative	
5	Imperial Irrigation District	Marcela Y Caballero	Affirmative	
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Negative	

5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	
5	PacifiCorp	Sandra L. Shaffer		
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn		
5	WPPI Energy	Steven Leovy	Negative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Abstain	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson	Negative	

6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Negative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	John Jamieson		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen		
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	
8		Edward C Stein		
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz		
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	California Energy Commission	William M Chamberlain		
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Midwest Reliability Organization	William S Smith	Negative	

10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	SERC Reliability Corporation	Carter B Edge		
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (83 Responses)
Name (52 Responses)
Organization (52 Responses)
Group Name (31 Responses)
Lead Contact (31 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (19 Responses)
Comments (83 Responses)
Question 1 (51 Responses)
Question 1 Comments (64 Responses)
Question 2 (55 Responses)
Question 2 Comments (64 Responses)
Question 3 (58 Responses)
Question 3 Comments (64 Responses)
Question 4 (55 Responses)
Question 4 Comments (64 Responses)
Question 5 (54 Responses)
Question 5 Comments (64 Responses)

Individual
Jim Watson
Dynegy
Yes
Yes
No
Perhaps R1 could be reworded to answer the following question: "If an entity registered only as a GO owns relays that trip the generator alone (and not relays detecting a fault on any transmission lines), does this Standard apply?”
Yes
Yes
Individual
Bob Thomas
Illinois Municipal Electric Agency
Agree
Florida Municipal Electric Agency
Group
US Bureau of Reclamation

Joe Uchiyama
JOe Uchiyama
Yes
1)We agree to isolate the least number of power system elments during a fault. However, PRC-027 & PRC-001 are lack of a statement which elements be reviewed by entities. It seems like it is upto utilities to decide wchich elements to be reviewed and studied for. For the comliance purpose, how does Autority judge the reviews/documents were meeting PRC-027? 2) Pg. 2- Definitions of Terms Used in Standard- “Interconnected Element: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.” – The Interconnected Element definition should be expanded upon and attached figures added showing what is and is not an interconnected element relative to the generator and generation owner. 3) Page 2 – The term “Functional Entities” as used in the definitions for “Interconnected Element” should include a definition. 4) Pg. 4- A.5 –“Other Aspects of coordination of Protection Systems addressed by other Projects: Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects.” – The paragraph should be more specific as to whether the “fault clearing” referenced is used for primary transmission line protection or primary generator/generator step-up transformer protection. Namely, does what is addressed in PRC-027-1 exclude fault clearing used for primary generator/generator step-up transformer protection? 5) Pg. 8- R3.- 3.1- “• New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios.”- The sentence should be changed to read- “• New installation, replacement with different types, or modification of: fault clearing protective relays or protective function settings, related communication systems, related current transformer ratios and voltage transformer ratios.” 6) Last paragraph on page 26 starting with “Protection Systems installed to detect faults on the BES…” has some great examples (especially the last sentence of that paragraph) of the intent of PRC-027. I think it would be useful to move or copy this type of verbiage to the beginning of the document and use it in the definitions to accomplish what Pete has commented on below.
Yes
Yes
Yes
Yes
Individual
Michelle R. D'Antuono

Ingleside Cogeneration LP
Yes
Ingleside Cogeneration agrees that it is appropriate that PRC-027-1 is self-contained throughout. Even though the Purpose statement is not necessarily mandatory and effective, it is conceivable that the previous version would lead a Compliance Enforcement Authority to require evidence that fault studies account for relay performance governed by other NERC standards. This could result in the assessment of two penalties for the same violation – a double jeopardy condition that should be avoided.
Yes
No
Ingleside Cogeneration, like many other Generator Owners, does not typically perform fault studies unless we have made material changes to our transmission system interconnection. Even then, we provide modeling data to the appropriate Transmission Owners and Transmission Planners, who execute the assessments on a Regionally-standardized platform. We are not convinced that we can add value to this process – other than to demonstrate that the information required by the TO and TP was provided, and the study took place. In our view, the requirement should clearly accommodate this working arrangement. As it reads now, it seems like both the GO and the TO must perform separate assessments. The extra costs that we will incur to commission external consultants is difficult to justify when there are so many other pressing priorities (e.g.; cold weather preparedness).
No
Ingleside Cogeneration still holds to the position that a dispute resolution process needs to be defined should we reach an impasse with the TO. R4 still requires that both parties "accept" the proposed change – which means that one or the other could unreasonably demand an Protection System-related expenditure without any need to demonstrate that a corresponding reliability benefit will be realized. It is not apparent to us that this situation is already addressed in NERC's Rules of Procedure, which ultimately is the governing document for continent-wide Reliability Standards.
Group
Northeast Power Coordinating Council
Guy Zito
No
By restricting the coverage to "… Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults" there is a significant gap in reliability created by the exclusion of elements such as loss of field, out-of-step, etc. An incomplete Protection System Study negates all the work needed to satisfy this Standard. Perhaps through referencing the NERC technical reference document entitled "Power Plant and Transmission

Protection Coordination", there could be a reference to which protection elements are going to be covered in this Standard and likewise what Standards will cover the protection elements not covered by this Standard. As identified by the Drafting Team, there may be no evidence of mis-coordination between traditional protections that detect faults, but for co-ordination of generator loss of excitation protection settings or out of step relaying during a fault condition – is that meant to be covered in this Standard or elsewhere? The latest draft of PRC-019-1 indicates studies conducted under that standard are for steady state conditions, not fault conditions. PRC-023 provided clear direction on what protection elements to mitigate and even provided options on how to mitigate those elements. PRC-027 should provide the similar effective vehicle to convey at least the "what" for Protection System coordination during faults between entities, and will allow entities to perform and document consistent Protection System Studies. The term "coordination" is not well defined. Does it mean ensuring owners of all terminals of a line, transformer, etc. are aware of each other's protection system design and settings, especially when the design, settings, and physical system changes? Developing a formal definition to be included in the NERC Glossary should be considered.
No
In the proposed definition of Interconnected Element "Functional Entities" is capitalized even though it is not in the NERC Glossary.
No
Due to the extensive documentation, coupled with the collaboration between entities associated with this requirement, NPCC believes 60 months is a more appropriate time frame to comply. This timeframe is also more in line with the timeframe proposed in the draft PRC-019-1 in Project 2007-09. An alternative to the "static" time frame discussed above, which would also be acceptable, would be to base the timeframe on a formula that factors in the number of interconnected power system elements that the entity must contend with.
No
This change is more ambiguous than reach agreement. How can changes to Protection Systems occur unless agreement is reached via a signed off Protection System Study? What does it mean to confirm acceptance?
Yes
We agree with the change. However, we are adding a comment on the VRFs. The VRFs should be High, not Medium. There are similar requirements in PRC-023-2 Transmission Relay Loadability, and TPL-001-2 Transmission System Planning Performance Requirements which have a High VRF. Also, from the Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 — Protection System Coordination for Performance During Faults, the FERC VRF G4 Discussion reads "Guideline 4- Consistency with NERC Definitions of VRFs: Failure to perform a Protection System Study for each Interconnected Facility to verify that Protection Systems coordinate such that the least number of power system Elements are isolated to clear Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk

Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC’s definition of a Medium VRF.” Poor protection system coordination during a disturbance can create severe system conditions faster than Operators can respond to them, leading to system instability or a cascading failure. These circumstances are consistent with the NERC definition of a High VRF.
Individual
Andrew Z. Pusztai
American Transmssion Company, LLC
Yes
However, ATC recommends that the Purpose statement in the Standard be modified by adding the word “intended” : “To coordinate Protection Systems for Interconnected Elements, such that the least number of intended power system Elements are isolated to clear Faults.”
No
The Interconnected Element definition should be expanded to clarify that PRC-027 is applicable to only BES Elements as demonstrated in Figure 4 of the Standard’s Application Guidelines on pg. 27. • ATC recommends that the SDT please modify the definition of Interconnected Element as follows: “A Bulk Electric System Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity” If “Functional Entity” is used and capitalized in the definition above, the term should be defined in the standard or be made part of the “Glossary of Terms Used in NERC Reliability Standards.” Furthermore, NERC’s “Reliability Functional Model version 5” states: “The following terms are used in the Functional Model and do not appear in the NERC Glossary. Functional Entity. The term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function.”
No
The SDT states that there is no evidence of wide spread misoperation due to lack of coordination. However, R1 requires a utility to establish an evidence package of legacy coordination that predates PRC-001’s effective date. While 48 months is an improvement to PRC-027, that timeframe still imposes a significant burden on utilities, especially those that are not vertically integrated. ATC recommends that the SDT consider changing the implementation period for R1 from 48 months to 72 months.
Yes
Yes
Group
ATCO Electric
Rowell Crisostomo

No
ATCO Electric (AE) has an existing protection review program that runs on 5 year cycle. Each year, AE review approximately 20% of AE’s transmission system to ensure the protection is in place or needs adjustment. Can the drafting team increase 48 month duration to 60 months?
Additional comments from AE that does not fit any specific question: (1) Timelines: There are too many hard timelines that aren’t consistent between individual requirements (24 months, 6 months, 90 days, 30 days, agreed upon time frame, prior to implementation, etc.). Keeping track of these timelines and evidence gathering will take considerable time and effort. Can the drafting team reduce the amount of timelines to make this standard manageable? Can the drafting team anticipate how to audit this standard during the standard development process? (2) There are requirements referred to other requirements and vice versa. Can the drafting team not to refer the requirements back and forth? Can the drafting team anticipate how to audit this standard during the standard development process?
Individual
Si Truc PHAn
Hydro-Quebec TransEnergie
Agree
NPCC
Group
Pepco Holdings Inc & Affiliates
David Thorne
No
The language in the Statement of Purpose needs to be reworded. The phrase “such that the least number of power system Elements are isolated to clear faults” may restrict certain protection practices in widespread use today, where coordination on tapped distribution facilities is achieved via auto-reclosing rather than via coordinated time delays. For example, a BES line (protected by a high speed DCB or POTT pilot scheme) is tapped by a distribution provider as demonstrated in Figure 3 of the Application Guidelines. Very often for distribution taps like these, rather than requiring the distribution provider to establish a costly transmission class pilot scheme terminal at breaker C with communication links to A & B, it is common to let the pilot scheme reach into (but not thru) the transformer at C. For faults in the transformer the high speed transformer relays will operate to trip and lockout breaker C. However, the pilot scheme at A & B will also trip simultaneously. Breaker C will lockout and A & B will auto-reclose to restore the line. Coordination is achieved via auto-reclosing. For faults on the line, A & B will trip via the pilot scheme, and if generation happens to be running either C will trip, or the generator will trip depending on scheme design. Reclosing at A & B would be delayed and / or voltage supervised to ensure generation has been removed prior to auto-reclosing. In the

above scenarios since the line tripped for a fault in the transformer, or the generator tripped for a fault on the line, it would violate the requirement that “the least number of power system Elements are isolated to clear faults”. The language used in the proposed definition of Protection System Study is better; using the phrase “demonstrates ... Protection Systems operate in the desired sequence for clearing faults”. The problem here is who determines what is the “desired sequence”? Would a scheme, which is purposely designed as described above and acknowledged by the Transmission Planner and Transmission Operator, be considered to operate in the “desired sequence” for clearing faults? The language in the standard needs to be re-visited to enable these types of protection interfaces with distribution providers having limited generation resources connected downstream. Also, if system reliability was truly an issue for this example, the interconnection should not have been a simple tap on the line, but rather a ring bus should have been established at the interconnection point. In conclusion, we suggest re-wording the Purpose to read: “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence for clearing Faults.” This statement is consistent with the stated definition of the Protection System Study, on which the measures of this standard are based.
Yes
No
Each owner should already possess information demonstrating that their protective devices are set to “coordinate” with adjacent protection systems. However, the documentation that presently exists may not be in the form of a formal “coordination study” in a format suitable for audit purposes. Some guidance should be provided indicating what form of documentation is expected, especially by the TO. For instance, on transmission tie lines between different TO’s coordination of zone distance elements is fairly straightforward and can be accomplished without a traditional “coordination study”. Also settings on pilot schemes need to be exchanged in order to allow for proper operation, but this is also not what is considered a traditional “coordination study”. On the other hand, coordination between GO’s and TO’s is even more complicated. Without some direction as to what specific documentation is required it is difficult to estimate how many existing interconnection points would have to be re-visited in order to produce the required auditable documentation. Some specific examples of what specific type of documentation is required would be helpful. To be safe, most likely all interconnection points would be revisited to ensure adequate compliance documentation. Also, for each revised Protection Study produced (per R1.1) a formal review (R1.2) and approval (R4.1) would be required. As such, with the large number of interconnection points on the system a 60 month time frame would be more appropriate. The SDT acknowledged that they had no evidence that there is widespread miscoordination between Interconnected Facilities when establishing the arbitrary 48 month requirement.
No
We find that changing the wording from “confirming acceptance” to “reaching agreement” does little to address the root problem associated with mandating mutual agreement. We suggest Requirement R4 be removed entirely or extensively re-written to address the concerns

outlined below: Requirement R4 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What if agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R4.2 until agreement is reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? This is the problem with mandating that an agreement between two parties be reached. It is further compounded by requiring that an agreement be reached within a set timeframe. It is unreasonable and unfair to hold one party non-compliant due to the failure of another party to reach agreement. Furthermore, in the example provided above, it is a detriment to reliability to delay implementation of the setting change on breaker D just because mutual agreement could not be reached. It is important to ensure that information on new, or modified, Protection Systems are shared between parties, so that each party may assess the impact of the change and ensure their Protection Systems are properly set and coordinated. The emphasis should be on sharing of information (such as relay setting changes) and not the details of performing the “Protection System Study” and all the associated approval schedules. As such, it may be reasonable to have a Reliability Standard to ensure setting information has been exchanged (which was the original intent of the PRC-001-1 standard). But it should be left at that. Mandating mutual agreement with compliance implications, without providing a clear division of responsibilities and assignment of who will be held non-compliant if agreement cannot be reached is unfair to either party.
Yes
We agree with this change. However, we have several other comments concerning this standard in addition to those expressed in response to Questions 1 thru 5. Usually there is a space on the comment form to enter these additional comments. Absent one, we offer these additional comments as an addendum to Question 5. 1) Requirement R2: The phrase “Facility associated with an” contained in R2 is confusing and unnecessary and should be eliminated. R2 should simply read “For each Interconnected Element on its System, the Transmission Owner

shall:” 2) Requirement R2, Parts 2.1.1 and 2.1.2: Remove the term “interconnecting bus” and replace it with the phrase “point of interconnection between the Entities.” The point of interconnection between the entities is more descriptive in that the interconnection point may not be a physical “bus”, but rather the terminals of a line disconnect switch, terminals of a breaker, specific transmission pole, etc. Even though the point of interconnection is often modeled in a short circuit program as a “bus”, the term “interconnecting bus” has no physical meaning. 3) Requirement R3, Part 3.3: A footnote should be added stating that this requirement does not apply to those temporary setting changes that sometimes are applied during commissioning, maintenance, or investigative testing activities to verify performance of individual protective elements, provided the original settings were returned upon the conclusion of the testing activity. For example, in multifunction relays when testing backup time delayed protective elements (i.e., zone distance or time overcurrent elements) it may be necessary to temporarily disable high speed elements (i.e., pilot or zone 1 elements). 4) The SDT states that “the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address the appropriate use of time delays in relays”. However, a word search of the 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. The mention of “the appropriate use of time delays in relays” in the 2003 Blackout Report was in the context of the actuating time of relays in response to system overload conditions, and generator protection to voltage and frequency excursions during stressed system conditions. The concern was that relays operated on overload before system operators could react and that some generators tripped (exacerbating the collapse) before other system schemes (UFLS or UVLS) could operate. The solution was not to increase the time delay on Zone 3 relays (which would have been intolerable for fault clearing purposes) but to address the relay loadability issue in PRC-023, to make them immune from operating under heavy load conditions. Similarly the premature tripping of generators on voltage and frequency protection during stressed system conditions (not fault conditions) and coordination with system UFLS and UVLS schemes was discussed in the report. Likewise those issues have now been addressed, or are being addressed, in PRC-006, PRC-010, PRC-022, PRC-019, and PRC-024. Similarly in the recent Southwest Blackout of 2011 the operation of relay schemes during overload conditions was a contributing factor. There was again no evidence of miscoordination of relay schemes during fault conditions. The unexpected operation of relays and SPS’s during overload conditions could have been avoided by proper application of existing standards PRC-023 and PRC-014-0. Based on the above, where is the historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions? Reliability Standards should be adopted based on a need to address a known, or probable, reliability issue. As such, although we support the overall desire to ensure that protective systems are “properly coordinated”; we see little value in developing a new Reliability Standard to address something that is routinely practiced and which has not been demonstrated to be a contributor to major system disturbances, or cascading outages. Even the SDT in their rationale for Requirement R1.1 stated that they have no evidence that there is

widespread miscoordination between Interconnected Facilities. In lieu of a formal standard to address relay coordination during faults, a simple technical reference document on Protective System Coordination issues may provide equal benefit to the industry. The above comment was also submitted with Draft 1 of the standard. In their response the SDT stated that PRC-027 was being developed in response to FERC Order 693. However, Order 693 only directs NERC to address specific deficiencies in PRC-001 surrounding certain measures and levels of non-compliance relating to the notification and response to the detection of failures in relay protection systems. As such, we believe PRC-027 goes well beyond what is was directed by FERC, and the stated purpose of the SAR. We urge the SDT to revisit FERC Order 693 and revise this standard as appropriate to address only the stated FERC directives.
Group
Western Small Entity Comment Group
Steve Alexanderson P.E.
Yes
Yes
No
The comment group agrees that Protection Systems associated with Interconnected Elements must be coordinated. However, the reliability goal should be strictly focused on documenting the associated owners (parties) are cooperating, and in agreement with protection settings to achieve proper coordination. A requirement to have a documented Protection System Study completed will not improve on a simple statement from the parties that proper coordination has been agreed upon. Provision of a Protection System Study as compliance evidence (in whole or a summary) implies recourse to check its completeness or accuracy. For complex systems, this is very subjective. However, the Standard as written intends to make no effort to verify the completeness or accuracy of a Protection System Study; the intent is to simply verify that it exists. Since the Protection System Study is not subject to review, its production as compliance evidence is nothing more than added bulk.
Yes
Yes
1. The comment group has no comments regarding this question. 2. This form provides no general comment area, so we are providing our additional comments here. We referenced the WECC Position Paper in the last round of comments, but now see that WECC did not submit comments. We urge the SDT to take a look at the paper. We received our copy from steve@wecc.biz . We can also forward a copy if an email address is provided. For the team's convenience, here is the relevant text: "WECC staff and WECC subject matter experts have reviewed the proposed standard and agree with the purpose of the standard. WECC staff and WECC subject matter experts agree that Protection Systems must be coordinated. However

some subject matter experts believe that the proposed standard requires more documentation than is necessary and that the requirement to provide a hard copy or an electronic copy of each Protection System Study is administratively burdensome and not reflective of the intent of Results Based Standards. These subject matter experts believe that evidence that studies are coordinated and that entities have agreed to the results of System Protections Studies is adequate.” We see that the SDT responded to Salt River Project’s and other’s similar concerns regarding hard copies by stating that that only summaries are needed, but we still see the standard as overly burdensome compared with the possible benefit. Tennessee Valley Authority, Dominion Power, Southwest Power Pool, the Nebraska Public Power District, Dairyland Power Cooperative, the Bonneville Power Administration, and the SERC Protection and Control Subcommittee provided some specific suggestions to reduce documentation burden which were all rejected. We urge the SDT to review these recommendations again.
Individual
NICOLE BUCKMAN
ATLANTIC CITY ELECTRIC COMPANY
Agree
Pepco Holdings Inc and Affiliates
Individual
Don Jones
Texas Reliablity Entity
Yes
Yes
The SDT may want to consider additional language for the Protection System Study definition, to clarify that the study demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults as well as clear the Faults within the maximum time frame defined by the Transmission Planner in order to maintain System Stability. Another consideration would be that the study incorporates all of the applicable Fault contingencies (Category B and C) as defined in the NERC Reliability Standards (TPL-002 and TPL-003) or any Regional standards.
Yes
No
TRE agrees with the need to notify the Facility Owner of the proposed changes. However, if the receiving entity does not agree with the proposed changes, there needs to be a venue to reach consensus. The receiving entity should be able to suggest changes based on technical rationale to resolve the disparities. A provision for dispute resolution needs to be provided. TRE suggests re-wording R4.2 to – “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, notify the Facility owner(s) associated with the affected Interconnected Element. If consensus cannot be reached on the proposed Protection System(s)

changes, each entity shall document the technical rationale for its position on each disputed issue prior to implementation.”
Yes
OTHER COMMENTS (not responsive to any specific question asked above): R2.2: We suggest a minor change "...indicates a deviation in ***single line to ground or 3-phase*** Fault current of 10% or greater ....” R3.1: Based on recent work by the Protection System Misoperation Task Force (PSMTF), changes in logic settings should also be included (e.g. directionality V/Q logic, trip equations, carrier echo logic and coordination timers, carrier dip switch settings, etc.). We would suggest modifying the first bullet to say”...modification of: protective relays or protective function or logic settings, communication systems,....” The SDT may also want to consider adding an item to the list - “Changes to the transmission system topology that change the equivalent impedance or fault current.”
Individual
Patrick Brown
Essential Power, LLC
No
The purpose is laudable, but the means by which it is to be achieved needs more work. The Application Guidelines section of PRC-027 makes reference to, “the entity performing the Protection System Study [for R1],” but the standard provides no indication of who this should be. This responsibility is simply assigned to, “Each Transmission Owner, Generation Owner, and Distribution provider.” The obligation placed on GOs by use of the word “each” in R1 cannot be fulfilled, however, except under the circumstance of having a vertically-integrated utility. An independent GO does not have knowledge of the TO’s system, and in a deregulated market is not allowed to have such knowledge. The TO and TOP are provided with detailed information of the GO’s equipment, however, and therefore perform all interconnection-related studies. This is as it should be, because changes in the transission don’t matter to a GO. We do not modify our Protection Systems in response to changes to the Fault current at an interconnecting bus, we just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Everything involving sequencing the tripping of multiple Elements is in the TO’s system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e. reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should say so, rather than pulling in all GOs regardless of whether or not it makes any sense for them to be involved. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performend by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.
No
The term Functional Entity needs a definition. It is capitalized in PRC-027 but is not defined in

the standard or in the NERC Glossary. It is nonetheless evident that a GO and TO are different Fnctional Entities, but the nature of the Element that joins them and thereby constitutes the Interconnected Element is unclear. Is this the transmission line? If so, would the TO be responsible for the R1 study if the ownership scope of an independent GO ends at the high-side terminals of the GSU or at an HV disconnect switch? Would the responsibility be shared if, as sometimes happens, the ownership split occurs at the fenceline, leaving a small part of the transmission line the property of the GO while the rest belongs to the TO? The definition of a Protection System Study needs to include identification of the party responsible for performing this work. This cannot be the GO if dealing with a deregulated market; since, as explained above, such parties are not allowed access to information about the TO's system.
No
The time frame is not the issue. R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.
Yes
Yes
Individual
Michael Mayer
Delmarva Power & Light Company
Agree
Potomac Electric Power Company, Transmission Owner (Segment 1)
Individual
Mark Yerger
Potomac Electric Power Compan
Agree
Pepco Holdings Inc and Affiliate
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
Yes
No
Suggest replacing Protection System Study with Coordinated Protection System Study.
Yes
Yes

No
IID believes the affected entity need to demonstrate it received notification.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
No
The purpose should mirror the objectives of the Protection System Study: “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence.” There are cases where industry practice is to “overtrip”, for example, for a tapped non-BES distribution transformer fault by tripping BES line breakers and reclosing. Also it may be a common practice to use zone 1 extension or acceleration schemes. There can be good reasons for intentionally tripping more than “the least number of Elements to clear a Fault”. The Purpose statement as currently written is in conflict with these valid industry practices, and needs to be modified.
Yes
No
We strongly believe that 60 months would be a more achievable time frame to study the many interconnections that an entity may have. This will also allow Generator Owners the time needed to gain the resources required to perform these studies, since they may not be presently so equipped. As stated by the drafting team in the rationale for R1 there is no evidence of wide spread mis-coordination of Protection Systems associated with Interconnected Elements. It would also be helpful to provide a better description of what is required to be included in a Protection System Study. For example, is the study required to include pilot scheme timing and element coordination, breaker failure coordination, coordination under minimum and maximum fault current cases, etc?
No
The current draft standard lacks any clear responsibility for performing the complete Protection System Study, especially if the interconnected parties cannot accept or reach an agreement. The recommended change is to make the Transmission Owner accountable for the overall Protection System Study, at least at the Generator-Transmission interconnections. The other entities such as Generator Owners should be responsible to provide the necessary data required for the overall study. This makes the most sense based on limited resources and capabilities, as well as access to all data. This is especially true for independent Generator Owners that operate in the deregulated market. It is not feasible to make all entities somehow responsible for the study.
Yes
Individual

Scott Miller
MEAG Power
Agree
Essential Power, LLC
Individual
Wryan Feil
Northeast Utilities
Agree
Northeast Power Coordinating Council Inc. (NPCC) 1040 Avenue of the Americas 10th Floor New York, NY 10018
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
Agree
NPCC, the Northeast Power Coordinating Council
Individual
Thad Ness
American Electric Power
Yes
No
AEP recommends replacing all references to “generator Protection Systems” with “Generator Owner equipment that provides backup system protection”, and suggest adding language to the standard for clarification. The scope of Generator Owner Protection Systems applicable to this standard is not clear from the verbiage within the standard or the definition of Interconnected Element. AEP believes that the SDT did not intend to require the GO to include all generator Protection Systems under this standard (as shown in Figure 2 on page 25 and Figure 5 on page 28 of the clean draft), but instead meant to limit the scope of relaying to be coordinated to only the Generator Owner equipment that provides backup system protection. AEP agrees with the definition of Protection System Study, however, we disagree with using the acronym PSS within the standard as PSS is also the recognized acronym for Power System Stabilizer. Usage of this acronym (for example, in the Process Flow Chart) would cause unnecessary confusion.
No
AEP believes that 48 months to complete a Protection System Study is too short of a time frame, especially for Interconnected Elements which do not have an existing study. NERC’s rationale for R1 states that “the drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame.” If this is the case, then there should be no issue with extending this

timeframe. AEP believes that 72 months is a more reasonable timeframe for the following reasons: * The Transmission Owner will need to complete their own studies, as well as provide data to the entities they interconnect with (i.e. TO’s, GO’s, and DP’s). This dependency would effectively shorten the amount of time the functional entity has to complete their studies to less than 48 months. * Before the work of the first bullet point above can be completed, entities must develop an agreed-upon list of Interconnected Elements and associated owners of the Protections System(s) associated with each Element. Once again, the time required to complete this task erodes into the entire time allowed to perform the study. In short, much of this work must be sequentially rather than in parallel, further justifying the need for an increased timeframe. * The resources needed to complete the required studies will also be impacted by a number of other standards currently in draft including: PRC-006-1, PRC-019-1, PRC-024-1, PRC-025-1 and PRC-004-3. The work required to perform both the proposed studies of this standard, as well as the other standards listed above, requires a Subject Matter Expert possessing a specific skillset gained from years of protection experience. Due to the limited number of such SMEs, industry will be very challenged in meeting all the proposed requirements given the limited number of such resources. In addition, the demand for qualified outside resources might be greater than their actual availability due to the time constraints involved.
Yes
Yes
Because the comment form provides no section to provide “general comments”, AEP offers them below. AEP would like to inform the drafting team that our negative vote on this standard is primarily driven by a) the lack of clarify in regards to its scope (as discussed in the response to Q2) and b) the timeframe allotted to perform the Protection System Study (as discussed in the response to Q3). It would be more appropriate for R 1.1.1 to be included in the implementation plan, rather than embedded within the standard itself. The proposed standard is difficult to follow, in the way that it jumps back and forth among requirements. We would encourage any changes which might increase the readability of the proposed standard.
Individual
Daniel Duff
Liberty Electric Power LLC
No
Functional entity is not defined. System Studies should be defined as "a study performed by a TO that demonstrates.....etc."
No
R1 should not apply to GOs. GOs are not allowed to have the TO information needed for a system study under market rules.
Yes

Yes
Individual
Nazra Gladu
Manitoba Hydro
Yes
Although Manitoba Hydro agrees with question 1, we have the following general comment: (1) The purpose statement and R1.2 refers to Elements within the ‘power system’ which is not defined, while the ‘Facilities’ refers to ‘Elements of the BES’ and the ‘Requirements’ reference Interconnected Element on a particular entities’ ‘System’ or ‘transmission system'. Should these be consistent or has this been done purposefully?
Yes
Although Manitoba Hydro agrees with question 2, we have the following general comments: (1) Please clarify why definitions are to remain with standard upon approval and not be moved to the Glossary. Are these definitions applicable only to this particular standard? If this is the case, this could lead to uncertainty if similar terms are going to be used or defined elsewhere. (2) Compliance 1.1 – The word ‘Compliance’ in the first line should not be capitalized and (CEA) should follow the word ‘authority’. Since ‘Regional Entity’ is a defined term, ‘Entity’ needs to be capitalized. (3) Compliance 1.2 – The second paragraph should begin with ‘Each’, not ‘The’. We suggest that the reference to an ‘Interconnected Facility’ in the second paragraph should be changed to ‘a Facility associated with an Interconnected Element’ to make it consistent with the rest of the standard, including the third paragraph of 1.2.
Yes
Although Manitoba Hydro agrees with question 3, we have the following general comments: (1) R2, 2.1.1 – Reference to the Protection System Study should be the most recent Protection System Study to be consistent with the rest of the requirement and the use of the word ‘available’ is a little problematic. What if no study exists? As we read it, the requirement to do a study is within 48 months of the effective date of the standard, while the requirement to do a short circuit study is at least every 24 months. If the Protection System Study is not available, is there no requirement to do the short circuit study? (2) R2, 2.2 – For clarity, we suggest rewording the first sentence to read ‘Within 30 calendar days after identification, through the calculation performed pursuant to Requirement R2, Part 2.1.2, of a deviation in…’ (3) R3, 3.1 – No time frame is given and it is unclear as to whether these details are to be only for proposed or future changes or additions, or whether it can be ‘notice after the fact’ (when read with the remaining requirements, it would be assumed it is ‘prior notice’, but that’s not clear on the face of this part 3.1). In addition, should ‘facilities’ be capitalized in 3.1? Also, there needs to be consistent references to ‘changes and additions’ or just ‘changes’ within this R3 as currently there are references to both made. (4) R3, 3.2 – We suggest moving the time frame to the start of the Part for consistency with the drafting of other Parts and for ease of reading. (5) R3, 3.3 –

We believe that the timeline is incomplete. Assuming that the timeline is meant to be 'within 30 calendar days of the (proposed?) changes or additions being made'. (6) VSLs/VRF table: R1, R3 – For consistency, the references should read 'less than or equal to 10 calendar days' instead of '10 calendar days or less'. (7) VSLs/VRF table: R4 – All of the references to 4.1 appear to be incorrect because 4.1, as currently drafted, does not require confirmation of acceptance of the summary results.
No
(1) R4, 4.2 – The concept of 'accept' the changes are problematic. We are unclear as to what exactly this means? Is it something more than acknowledging that the changes are occurring? Does it go so far as 'agreement' with the changes? What happens if the owner does not 'accept' the changes? (2) R4, 4.1 – For consistency with wording the in R3, 'planned change' should be 'proposed change' or 'addition'.
Yes
Although Manitoba Hydro agrees with question 5, we have the following general comments: (1) M1 – The word 'that' in the third line should be deleted and we believe that the words 'is dated documentation' are missing after 'Acceptable evidence for Requirement R1, 1.2. (2) M3 – For consistency, the word 'formula' should be replaced with calculation in Requirement R2, 2.1.2. (3) M4 – For clarity and consistency with the other Measures, we suggest rewording the opening sentence to read 'Acceptable evidence for Requirement R2, Part 2.2 is dated documentation (hard copy or electronic file formats) demonstrating that the updated Fault current values were provided within….'. (4) M5 – The wording of this section does not match the wording of the requirement. The words 'in hard copy or electronic file formats' should follow the word summary, not after the word settings.
Group
Midwest Reliability Organization NERC Standards Review Forum
Joseph DePoorter
Yes
Yes
No
The NSRF recommends that this Standard be filtered through the paragraph 81 criteria. If not, the NSRF recommends the following items. Although supportive of the extended timeframe in R1, the NSRF is concerned that the proposed Part 1.2 is overly prescriptive. Considering the sheer quantity of microprocessor relay settings that could potentially be reviewed as part of a Protection System Study, having to provide associated owner(s) the results of every protective relay setting reviewed would be unnecessarily burdensome with little benefit to reliability. Recommend the drafting team revise Part 1.2 to require entities to only provide information related to settings being proposed for change and have all other settings be made available upon request. Please clarify the application of R1, Part 1.2 in the event that both ends of the

Interconnected Element are owned by the same entity. In consideration that final settings and internal documentation would provide proof that everything was looked at accordingly, would the entity still need to develop and distribute a summary internally as well? Recommend revising Part 1.2 to only require functionally separate entities to provide documentation of the results of the Protection System Study. Rather than specify the details to be shared as a result of a Protection System Study, recommend Part 1.2 be modified to remove “power system Elements to be isolated, contingencies evaluated” as a minimum requirement. Having entities share their evaluation methods with other Entities appears to be unnecessary administrative work. Considering that it is the responsibility of the individual entity to perform their studies correctly, another entity should not have to worry about, nor does it have the responsibility for keeping tabs on, whether an external study was done to a single or double contingency level, what external Facilities become isolated, etc. Additionally, the NSRF is concerned with the phrase “Fault current used” as it applies to R1, Part 1.2. In consideration that Fault current values do not necessarily mean that two entities are using like models, recommend a comparison of boundary equivalents be used instead to ensure that the models are comparable between entities. If not, entities would potentially be sharing every value for every iteration to ensure like models. Suggested revisions to R1, Part 1.2 in support of the above comments are as follows: 1.2. Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with Interconnected Element(s) that include two or more Registered Entities, a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, proposed revisions to the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, boundary equivalents at necessary buses Fault currents used, any issues identified, and any additional revisions proposed). If existing documentation does not include enough detail to meet the requirement for an acceptable Protection System Study, utilities will be forced to add to the existing documentation for compliance purposes even though the existing settings coordination is adequate. This will place additional compliance burden on utilities while not necessarily improving reliability. Since there is no evidence of widespread mis-coordination of Protection Systems associated with Interconnection Elements, it would seem reasonable to have this standard apply to any changes made to an existing Protection System or all new Protection Systems.
No
R4, Part 4.2: In consideration that R4, Part 4.1 already requires entities to review the results of a Protection System Study and provide any related feedback, recommend Part 4.2 be removed from the standard. Without additional guidance within the standard specifying the timeframe in which an entity must provide its confirmation, the entity implementing the planned change could potentially be left waiting indefinitely for confirmation despite the study already being reviewed and accepted as part of Part 4.1. If part 4.2 is not removed, recommend that additional guidance be provided concerning time frames (90 days?).
In addition to the previous comments outlined above, the NSRF offers the following comments for the drafting team’s consideration. Recommend the timeframes in R1.1.1 and R2.1 be stated in calendar years. The NSRF is concerned that a utility would be found in violation of this standard if one study was done in February of 2012 and the next one in March 2014 based on

the current wording. The intent of a results-based standard is not to have these types of technicalities built into them. An entity cannot study a part of the system that they do not own. The examples at the end of the draft in the Application Guidelines appear to imply that they should. Settings should be obtained from remote ends of a tie line only to be used in conjunction with studying the settings for which an entity has direct control. If an entity can't issue setting changes for a relay, then the entity can't study it to see what the settings should be. If both ends need adjustment then an iterative coordination back and forth between Entities should be performed. The majority of utilities would not feel comfortable accepting an external entity's settings changes for their own equipment. Recommend additional wording be added to the Application Guidelines to the further clarify the drafting team's intent. R2, Part 2.1.1: Recommend R2, Part 2.1.1 be revised to only require short circuit values be 'studied' at buses for which the entity in question specifically owns. For Interconnected Facilities between two entities, fault current values should be 'requested' by the neighboring utility. This would be beneficial to ensure that both entities are comparing models to keep them as up to date as possible. Better yet are boundary equivalents as discussed in previous comments. R2, Part 2.2: Similar to our previous comment for R1, Part 1.2, the proposed language in Part 2.2 appears to indicate that internal Interconnected Elements would require additional documentation and notification beyond what is necessary. This should only be required of Interconnected Elements in which there are two or more owners. Proof of study should be adequate for internal situations. 2.2 Within 30 calendar days after identification where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates a deviation in Fault current of 10% or greater, provide each owner of the Protection System associated with the Interconnected Element, that include two or more Registered Entities, the updated Fault current values (Iscs).
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Agree
Support both the previous comments of Bonneville Power Administration and the comments of the Western Small Entity Comment Group
Individual
Kayleigh Wilkerson
Lincoln Electric System
Agree
MRO NSRF
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes

Yes
Under figure 2 in the application guidelines the example need to be reviewed and text added to clearly identify the intent of the drafting team. For example is the scope for Generator Owners in figure 2 just the backup system protection for the Transmission Owners system? It's not clear in the examples given. This issue is also present in figure 5. We agree that if the scope is just for the backup system protection it is ok but the wording does not clearly state this. Also using PSS as an acronym for Protection System Study could be confused in the flowchart of this standard with power system stabilizers since there isn't any text to spell out that it is referring to Protection System Study.
No
We are concerned that 48 months could still not be sufficient for these studies. We would ask that the team consider 72 months. There is a concern that with all the companies having new standards to comply with, the Transmission Owners/Generation Owners are being overloaded and have the same resources.
Yes
Yes
Group
National Grid and Niagara Mohawk (A National Grid Company)
Michael Jones
Yes
Yes
No
How would "fault currents used" be presented for coordination of distance relays ? Also if the above items must be included, at a minimum, they need to be enumerated in requirement R1.
No
It is not clear where the old text "reach agreement" and the new text "confirming acceptance" were/are used. Also, "confirming acceptance" is vague in meaning.
Yes
National Grid offers the following additional comments that do not pertain to Question 5. The comments are included here since the Comment Form did not have an additional question concerning if we had additional comments. 1. Page 4: Other Aspects of coordination of Protection Systems addressed by other Project needs to be included in the final standard since it delineates what is not included in this one. 2. Page 8: Para.R2.1.2 should be reworded as it allows for a series of increments in fault current each less than 10% but which when summed over a number of review periods could collectively exceed 10%. 3. Application Guidelines: a.

Page 21: “Data used to determine Fault currents….” is essentially the short circuit model and the associated data base of line, transformer and generator impedances and connections. If that what is expected then it should be so stated otherwise “data” leaves a lot open to the reader’s conjecture. b. Page 25: Decision point regarding R2.1.2 has the same issue as identified above in comment 2. c. Diagrams Fig. 1, 2, 3, 4, 5: The text that goes with these diagrams is inappropriate in its assignment of responsibilities for who reviews what coordination and the change of wording from “verify” to “review” does not resolve this problem. It is a protection system owner’s responsibility to coordinate their system with adjacent systems and it is the same owner’s responsibility to model adjacent systems in sufficient detail to enable that owner to perform that coordination. Fig . 2, 5: The text refers to “generator protection” which can mean a wide range of protection functions such as but not limited to those related to voltage, frequency, loss of field, over-excitation and more. These were excluded on page 4 of the standard and their exclusion here should be emphasized. Fig. 3, Notes following figure 3 exclude reverse power as being a protection system installed to detect faults on the BES Transmission System. We disagree. In our system and other systems in NE reverse power was historically installed specifically to detect and clear backfeed to a faulted transmission system.
Group
Salt River Project
Bob Steiger
Yes
Yes
No
Agree with timing, but confirmation from both parties that coordination has been reviewed should be adequate evidence.
Yes
No
Receipt of confirmation should be required to confirm coordination.
Group
Bonneville Power Administration
Chris Higgins
No
The Purpose given assumes that the most important outcome of a protection system operation is that the least number of power system elements are isolated to clear a fault. While it is true that it is usually desirable to prevent parallel paths from opening, in many cases it might be

perfectly acceptable for adjacent elements to operate. BPA believes it may be more economical to have a protection system that isolates elements in addition to the faulted element if the isolation of the additional elements does not result in problems for the BES. A suggested Purpose statement that takes this philosophy into account is: To insure that separate Functional Entities properly coordinate with each other the protective systems for elements that interconnect their electrical systems so that only the intended power system elements will be isolated to clear a fault.
No
With regard to the definition of Interconnected Element, BPA believes the term should be interconnecting element, because the element is not interconnected, rather the systems of the functional entities are interconnected by the element. The point of interconnection between two functional entities is typically where two elements meet, such as between a line and a switch, and it is not a clear which element is the interconnected element. For example, suppose that a line from one entity terminates through a breaker at the bus of another entity's substation. Which is the interconnected element, the line, the breaker, or the bus? In another example, a generator ties to a transmission providers BES through a step-up transformer. Which is the interconnected element, the step-up transformer or the transmission line? Additionally, if a distribution provider taps off of a transmission provider's 230kV line through a disconnect switch, is the disconnect switch the interconnected element? BPA asks that the definition of Interconnecting Element be further clarified to provide the specific criteria that entities are expected to apply to come up with a consistent response in all such instances. The SDT attempted to illustrate the concept of the interconnected element through some examples in the Application Guidelines; however, the selection of the interconnected element in these examples neither follows logically from the standard nor provides the additional clarity necessary to enable industry participants to apply it in a manner that enables all users to come up with the same answers.. BPA believes the standard needs a clearer definition of an interconnected element. With regard to the definition of a protection system study, the definition given is too vague to provide a clear understanding of what is required by the standard.
No
BPA believes that the requirement to provide a protection system study for each interconnected element is onerous, and as a result, any amount of time is too short.
No
According to this standard, something as simple as changing a CT ratio must now be communicated to all interconnected functional entities and documented. The interconnected functional entities must then "confirm acceptance" of the CT ratio change before the change can be made. The acceptance must then also be documented. This level of bureaucracy is unnecessary and counterproductive. The change from "reach agreement" to "confirming acceptance" is irrelevant.
No
BPA believes that the requirements and measures are onerous and should be eliminated. The change in wording is irrelevant. Additional Comments R1.1 requires a protection system study

to be performed, but does not explain what is required for a protection system study. R1.2 lists some minimum requirements of a protection system study, but leaves many unanswered questions, for example: Which relays must be included in the study? Where are the faults to be applied? What contingencies should be applied for the study? How many buses back into the system must be reviewed? R1.1.2 introduces the term “interconnecting bus” with no definition of what it is. R2 is a requirement that pertains to each facility associated with an interconnected element. The use of the word “associated” is too vague and leaves the interpretation of this requirement wide open. In R2, the need to perform a new protection system study is based on a 10% or greater increase in fault current. Since many relays are based on impedance or differential methods, the value of fault current has no bearing on their need for a coordination review. R2, therefore, results in an unnecessary and useless burden when applied to elements protected with these relays.
Group
GP Strategies
Mary Jo Cooper
Yes
No
We do not believe that the drafting team appropriately identified the correct Applicable Functional Entities for this Standard. We also believe existing Standards could be modified to resolve any reliability gap rather than creating a new Standard. As a result, while the Purpose of this standard may seem to be reasonable, we feel that the drafting team should either 1)Change the Purpose to state “To conduct necessary studies to ensure Protection Systems for Interconnected Elements are studied, such that the least number or power system Elements are isolated to clear Faults.” And change the Applicable Functional Entities to the Transmission Planner or 2) modify existing Standards, instead, as described below. The short-circuit studies should be conducted by the Transmission Planner. From Appendix 5B of the Registration Criteria the: • Transmission Planner is the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.” • Distribution Provider is the entity that provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.” TPL-001, TPL-002, and TPL-003 already require the system studies are conducted. These Standards should be modified to include any additional studies that the drafting team feels are a gap. As noted in the drafting teams Rational for Part R2.1 “Short circuit databases are customarily updated annually so the drafting team believes 24 months provides entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation.” That being said, there is no current Requirement for the Distribution Provider to provide the information to the databases so that the Transmission Planner can conduct the

studies on the Interconnection Facilities. We recommend that MOD-010 and MOD-012 should be modified to include the Distribution Provider instead. For new facilities, FAC-002-1 already requires the coordination of changes in the Facilities.
Yes
Yes
Yes
Group
Arizona Public Service Company
Janet Smith
APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
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Individual
John Seelke
Public Service Enterprise Group
No
What information comprises a Protection System Study (PSS)? In the Application Guidelines, from Figure 1 on p. 24, each owner that receives a PSS is “to review the Protection System setting” associated with the other owner’s breaker that would operate to clear a Fault on the transmission line that connects each Interconnected Element. Is this (Protection System settings) the ONLY information that needs to be transmitted in a PSS by each owner? The SDT should itemize ALL of the information it believes needs to be included in a PSS that is to be transmitted between owners of an Interconnected Element and include that information in the examples in the Application Guideline. This information should also be listed into the PSS definition, thereby defining its scope.
No
The issue is consistency in what comprises a valid PSS. For example, for "contingencies evaluated," it seems that each owner should evaluate a core set of the same contingencies as opposed to this being an owner-by-owner decision. The lack of specificity as to what is required for a PSS is the issue.
Yes
Yes
Group
Luminant
Brenda Hampton
Yes
Yes
No

Comment on Requirement R1.2. The time frame listed may not be adequate under all circumstances or situations. Luminant recommends that the language be changed in this requirement as follows: "… Protection System Study performed pursuant to this requirement (including at a minimum, the Protection System(s) reviewed, any issued identified, and any revisions proposed) shall be within 90 days or in accordance to an agreed-upon schedule with a Transmission Owner, Generation Owner, or Distribution Provider." This would align with R4.1 that also provides the same time frame. The corresponding measures will also need to be modified if this language is accepted.
Yes
Yes
Individual
David Jendras
Ameren
Yes
We are voting negative for three reasons, one provided below and two are included in response to Question #3. Ameren also supports the SERC Protection & Control Subcommittee (PCS) comments and hereby includes them by reference rather than repeating them all. (1) We request that the SDT replace "detect Faults on the BES Transmission System" with "protect the BES Transmission System" in all three places where it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry.
Yes
Yes
(2) Requirement R2 requires short circuit study every 24 months even though the SDT's own rationale is that other requirements will trigger Protection System Studies first. Thus we believe that R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. (3) VSL escalation in 10 days is not representative of the severity of the violation. The SDT correctly points out in R1 rationale that it "has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements." We have about 500 Interconnected Elements per our present understanding of Draft 2 definitions and guidance. We recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity's Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively. Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation.

Yes
Yes
Group
Operational Compliance
Ed Croft
Yes
Yes
Yes
It would be great if NERC provided a common format for all of us to use when providing this information
Yes
Yes
Individual
Chris Mattson
Tacoma Power
Yes
No
Where is the term Functional Entity defined? Consider changing the term Protection System Study to Protection System Coordination Study. There are two reasons for this recommendation. First, the abbreviation for Protection System Study is PSS, which is also the common abbreviation for power system stabilizer. Second, the term Protection System Coordination Study emphasizes the primary purpose of PRC-027-1: to coordinate Protection Systems.
Yes
Yes
Yes
Additional Comments: Why is there a version 4 for PRC-001 (under Version History) when the

standard being balloted is version 3 (PRC-001-3). PRC-027-1 does not appear to impose any requirements as to how quickly issues identified in a Protection System Study are addressed. It may be difficult to impose such a timeframe since some issues may just require a relay setting change, while others may require more drastic scheme modification, including design, procurement, installation, and commissioning. Perhaps requirements could be added to develop, within a specified timeframe, and then implement a mutually agreeable Corrective Action Plan. As written, it appears that an entity can be compliant with Protection System Studies that always indicate existing coordination issues, which does not completely achieve the purpose of the standard. Without a mechanism to close the loop, PRC-027-1 appears to require a lot of documentation and coordination without any guarantee that existing coordination issues will ultimately be resolved. R4.1 really only requires entities to come to terms on the Protection System Study, but does not explicitly require any other course of action on existing coordination issues. In M1, the sentence ending in "…demonstrating that the time frames specified in Parts 1.1.1 and 1.1.2" in a fragmented sentence. Also, should this sentence have "and 1.1.3" at the end? M2 is a fragmented sentence. M4 is a fragmented sentence. As written, it may be difficult to audit parts of R3.1. Some of the language seems to be subjective and implicitly left to engineering judgment. First, it is not completely clear what the drafting team intended by the wording "associated with" or how an auditor might interpret that wording. Second, please consider changing "…or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s)" to "…or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s), as stipulated in the existing Protection System Study." This should make it easier to audit this aspect of R3.1. Third, regarding the second through fourth bullets, engineering judgment will be required to determine when impedances need to be changed. For example, minor modifications could be made to a transmission line that, in a purely academic sense, could change the impedance; however, an entity may opt not to update the impedance based upon engineering judgment that the change is not significant to the impedance model. For emphasis, under R3.2, considering changing "…within 30 calendar days of receiving a request or according to an agreed-upon schedule" to "…within 30 calendar days of receiving a request or according to an agreed-upon schedule, which may be longer or shorter than 30 calendar days." R4.2 does not seem to explicitly require that a Protection System Study be completed before implementing changes indicated in R3.1, only that the changes are accepted. R1.1.3 seems to suggest that the Protection System Study must be completed prior to implementation. However, according to the flow chart, it appears that a Protection System Study could be produced (in theory) six months after the changes were made. Furthermore, the flow chart applies the six-month timeframe even to R1.1.3, which does not match the text in R1.1.3.
Individual
Jonathan Appelbaum
The United Illuminating Company
Agree

Northeast Power Coordinating Council (NPCC)
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
Yes
Yes
No
Request consideration in replacing the time increment of 48 months with 4 years for the time frame.
Yes
Yes
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
Yes
Yes
Yes
Yes
(1) Austin Energy (AE) notes an inconsistency in R1.1.3 and the flowchart on page 22 of the clean version of Draft #2. R1.1.3 states that a Protection System Study is required “according to an agreed upon time frame” whereas the flowchart on page 22 says “perform the PSS within 6 months.” AE asks the SDT to update the flowchart to match the requirement language. (2) AE believes the VSLs for R4 are not consistent with the language of the standard, specifically R4.1 and R4.2. For example, the Severe VSL language should read “The responsible entity reviewed the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and responded as to whether further action is required, all per R4, Part 4.1, but was late by more than 30 calendar days. OR The responsible entity failed to review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to

whether further action is required, all per R4, Part 4.1. OR The responsible entity failed to confirm acceptance of any resulting Protection System(s) changes prior to implementing any planned change(s) associated with Requirement R3, Part 3.1 per R4, Part 4.2." AE is concerned about the current VSL language because it indicates the need to confirm acceptance of planned changes (e.g., new installation) instead of the resulting Protection System(s) changes.
Individual
Jim Howard
Lakeland Electric
Agree
FMPA
Individual
Larry Watt
Lakeland Electric
Agree
Please see FMPA comments.
Group
Dominion
Louis Slade
Yes
Dominion appreciates the SDT's agreement that in PRC 001 there were different interpretations of the term "coordination. Based on the SDT response to our Draft 1 comment regarding "coordination", we now understand that 'coordination' in PRC 027 Title and Purpose is referring to the technical aspects of coordinating relay settings. 2). Please reconsider Dominion previous recommendations to change the Title. "Protection System Interconnected Element Coordination for Performance During Faults" or "Protection System Coordination for Interconnected Elements" have more specificity and meaning to the standards intent for coordinating relays on interconnections.
Yes
Yes
Yes
Dominion interprets the wording "confirming acceptance" to mean that there are no major disagreements and that generally the methods between entities are acceptable using industry protection practices even if different protection setting philosophies' exists. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually

agreed upon response time, can be considered as confirmation of acceptance. The initiating party should not be restricted from applying appropriate settings due to the lack of acceptance confirmation from the other entity.
Yes
1). Please replace “detect Faults on the BES Transmission System” with “protect the BES Transmission System” in all three places it appears in Figure 3. This proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 2). Dominion respectfully disagrees with the SDT feedback comment on Draft 1 where it was recommended to remove references from one Requirement to another Requirement. Dominion was not challenging consistency with the recommendation but were stating the need to simplify the wording in the standard. Each Requirement can stand on its own without the additional Requirement reference. By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement due to the fact that that it causes you to read between Requirements. Isn’t this the purpose of the Process chart in the guidelines? 3). Under R1 – MI measure wording does not read as a completed statement. Dominion suggests removing ‘that’ from the first sentence to “….demonstrating time frames”. 4). Dominion respectfully disagrees with the SDT feedback that in R2 the term “deviation” is synonymous with “change”. Deviation refers to variation from a standard, norm or mean. This is not a statistical calculation but a simple measure of change 5). In R3- 3.2, there appears to be a formatting issue. Any Requirement that references a calendar day is worded where the Calendar date is at the beginning of the statement; for example R3- 3.3. Need to change wording in R3- 3.2 for consistency throughout document to read “Within 30 calendar days of receiving a request or according to an agreed upon schedule, requested information related to coordination….”). 6) In Draft #1 Dominion wrote: “Throughout this Draft 1 of the standard, there are references that illustrate documentation requirements that are inconsistent. Recommend all be written as “(hard copy or electronic file formats)”. The SDT responded saying “Each measurement in the standard (M1 through M10) has as evidence the statement “dated documentation (hardcopy or electronic file formats).” This is not the case; the point was that M1 reads “either in hardcopy or electronic file formats”. This is minor but needs to be changed for consistency.
Group
SERC Protection and Controls Subcommittee (PCS
David Greene
Yes
Based on the SDT response to our Draft 1 comment regarding the use of ‘coordination’, we understand ‘coordination’ in the Title and Purpose to mean the technical aspect of relay coordination.
Yes

Yes
Yes
1) The protection criteria and philosophies between entities can differ. For example, one entity may use the practice of coordinating for normal and single worst case contingency conditions, which is included in information/documentation provided to the neighboring entity in such Protection System Studies. The neighboring entity may have a slightly different protection criteria or philosophy, so exceptions may be required on a case by case basis using the “art and science” of protective relaying. Therefore, interpretation of ‘confirming acceptance’ means there may be differences in protection elements used by each entity but that there were no major disagreements and that generally the methods were acceptable and included using industry protection practices. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance.
Yes
Other comments (not associated with Question 5) are being provided which could not be addressed in the questions listed above: 1). R2 requires short circuit study every 24 months even though the SDT’s own rationale is that other requirements will trigger Protection System Studies first. Thus R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. 2). Please replace “detect Faults on the BES Transmission System” with “protect the BES Transmission System” in all three places it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 3). VSL escalation in 10 days is not representative of the severity of the violation. The SDT correctly points out in R1 rationale that it “has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements.” Many entities have numerous Interconnected Elements, and recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity’s Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively. Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation. 4). Throughout the 1st and 2nd draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.1.1, R2.1.2, R2-2.2, R4-4.1, R4-4.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. We appreciate the Drafting Teams perspective, but the SERC PCS believes that such cross references are

confusing. 5). Under R1 – MI measure wording does not read as a completed statement. Suggest removing 'that' from the first sentence. 6) The process chart is a direct indication that this process and undertaking for entities will be overwhelming. New systems will be required to track many details of timeframe requirements and communication dates. Additional resources will be required placing increased workload for an effort to change the process that already works for us when working with other entities. The Drafting Team indicated, 'there is no evidence there is widespread miscoordination of protection systems.'
Group
ACES Standards Collaborators
Ben Engelby
No
(1) We disagree with the inclusion of the "least number of power system Elements" in the purpose. The purpose should be to simply coordinate the Protection Systems for Interconnected Elements. While trying to minimize the number of Elements that should be removed from service is a laudable goal, it will create an incentive for auditors to determine if there is a better way to protect the registered entities systems. How else could an auditor know that the absolute minimum of Elements have been determined unless they tried optimize the zone of protection themselves. The use of different but related terms causes confusion. For instance, what is the difference among "power system Elements," "Elements," and "Interconnected Elements"? Based on the definition of "Element," we assume "power system Elements" is intended to be the same. If so, we suggest dropping "power system" to avoid confusion. (2) Similar to the purpose statement, the Applicability Section, (4.2) Facilities is unclear. The statement "Interconnected Elements of the BES that require coordination for isolating those faulted Elements" includes superfluous language. In general, NERC enforces standards against the BES. Thus, it is not necessary to include "of the BES." To ensure absolute clarity, we suggest the definition of Interconnected Element be modified to specifically limit it to the BES as well. Also, we recommend striking everything after Interconnected Elements in the purpose statement as it is unnecessary and provides no additional clarification on the Facilities to which the standard applies. (3) Because no generic questions asking for additional comments was provided, we are providing our concerns that do not fall under one of the specific questions asked of the drafting team here. (4) Please change the wording of Part 1.2 as the current wording has some unintended consequences. We think "to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement" should be changed to "to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of the associated Protection System Study." The current language literally reads that the TO, GO, and DP shall provide the PSS results to itself. It also reads that all the Protection System Studies for a TO, GO, or DP must be provided to the other protection system owners of all of the Interconnected Elements even if the other owners only own protection systems for one of the TO, GO, or DP's Interconnected Elements. As an example, consider that TO X shares two separate Interconnected Elements with TO Z and GO A.

The Interconnected Element between TO X and TO Z is called Tie-line B and the Interconnected Element between TO X and GO A is GSU C. The requirement would literally require TO X to share its Protection System Study results for both Tie-line B and GSU C with both GO A and TO Z even though, GO A has no interest in Tie-Line B and TO Z has no interest in GSU C. This could be solved with the simple edit described above. (5) We find that addition of "For each Facility associated with an Interconnected Element on its System" in R2 confusing. First, what is an associated Facility? Second what is intended by the use of Facility instead of Element? Considering Interconnected Facility in the last draft was change to Interconnected Element and Facility was used in this requirement, it would appear some delineation is meaning is intended between Element and Facility. Since Element and Facility have nearly the same meaning in the NERC Glossary of Terms that delineation is unclear and we would appreciate further explanation of the intent. (6) We found the inclusion of quotes on the phrase "Protection Systems installed to detect faults on the BES Transmission System" confusing. There is no reference. We suggest removing the quotes as they are superfluous. The meaning is still communicated without them. If they remain, please provide a reference. We assumed it came from section 4.2. If the quote did come from that section, it is not quite correct. It is missing "for the purpose of detecting" and "faults" is not capitalized. (7) The purpose statement of PRC-001-3 needs to be further modified. With the deletion of all of the requirements but Requirement R1, the purpose to "ensure system protection is coordinated among operating entities" is no longer achieved.
No
(1) We recommend modifying the definition of Interconnected Element such that is dependent on actual registered entity ownership rather than functional entities. As an example, a generation Element would only be considered an Interconnection Element if the GO and TO were separate corporate entities. If the functions were the same registered entity, coordination would already occur and the generation Elements should not be considered an Interconnected Element. To do otherwise will only cause significant compliance problems that may not support reliability. A utility that owns generation and transmission may not have a clear point of interconnection. This would be especially true for units installed prior to the advent of open access in the mid-1990s. If the point of interconnection is not well defined, how can an Interconnected Element be defined? It would be arbitrary to pick the GSU or an Element in the switchyard. Furthermore, focusing on ownership would actually make the proposed standard consistent with the existing PRC-001-2. That standard does not explicitly require coordination among different function entities within the same registered entity. (2) Interconnection Element definition is proposing an administrative burden of having to coordinate within the same registered function. Documenting coordination efforts made to external functions is reasonable for reliability; however, keeping records of internal coordination is unnecessary. What would an entity be required to show if there was only one protection system engineer in the organization? Would that single person be required to document coordination among him/her self? We feel that this portion of the definition should be struck – it is more appropriate to clarify the coordination of protection system elements should be among external registered entities in the requirements. There should not be any requirement for internal protection system coordination, especially not in a definition.

No
(1) While we do not disagree with the time frame, we question if it should be part of the requirement. It makes more sense to include the time frame for initial compliance of a requirement in the implementation plan. In that way, the initial compliance time frame does not persist in the standard long after it is no longer needed. It is common to utilize the implementation plan to describe initial compliance dates, especially when the requirement is asking for documented studies. After the studies are complete, there is not a need for a timeframe. Furthermore, FERC approves implementation plans as part of the standards package so there is no issue with whether the implementation plan is enforceable. (2) Conceptually, we agree with the intent of the standard and this requirement as it is presented in the application guidelines. However, more refinement is needed to make this requirement mirror what is explained in the application guidelines. For instance, we recommend clearly stating in Requirement R1 that the responsible entity is only responsible for performing Protection System Studies (PSS) for only those breakers it owns and are protecting the Interconnection Element. The standard is close to capturing this intent with the statement "its System" in Part 1.1. It would be better it if was changed to "Perform a Protection System Study for each of its Protection Systems that are protecting an Interconnected Element." A GO and DP do not really have systems so the current language is not appropriate for these functions. The application guidelines provide this clarity and would be helpful if the intent was clearly stated in the requirements.
Yes
(1) We had no issues with the use of agreement in the previous version. Coordination of protection systems is important enough to obtain agreement. Furthermore, we believe confirming acceptance and reaching agreement are synonymous. If two entities need to "resolve differences and confirm acceptance that their Protection Systems are coordinated," that is the same as stating that the entities need to reach an agreement.
No
(1) The measures do not match the requirements. For example, R4 requires entities to confirm acceptance, which would demonstrate that each affected entity received notification. Again, the drafting team is using synonyms that produce the same result as the prior draft. To show evidence that the information was "provided" would have to be some sort of notification of receipt. (2) Does the drafting team intend further actions for coordination beyond providing the studies to applicable entities? (3) We recommend the drafting team develop an RSAW to better explain how compliance would be measured against this standard. (4) Thank you for the opportunity to comment.
Group
Hydro One Networks Inc.
Sasa Maljukan
Yes
We agree with this Purpose statement and we commend the drafting team for moving this

standard in the right direction. However, in line with our previous comments from the first posting, there still seems to be a significant gap in reliability by not identifying what elements of the Protection System need to be co-ordinated between entities. Perhaps this can even reside in the Application Guide. A poor or incomplete Protection System Study is worthless and negates all the work needed to satisfy this standard. As identified by the drafting team, there may be no evidence of mis-coordination between traditional protections that detect faults, but for co-ordination of say generator loss of excitation protection settings or out of step relaying during a fault condition – is that meant to be covered in this standard or elsewhere? The latest draft of PRC-019-1 indicates studies conducted under that standard are for steady state conditions – not fault conditions. PRC-023 provided clear direction on what protection elements to mitigate and even provided options on how to mitigate those elements. We feel PRC-027 is an effective vehicle to convey at least the "what" for Protection System co-ordination during faults between entities and will allow entities to perform and document consistent Protection System Studies.
No
For Protection System Study: Suggest adding a phrase:"A study between two or more interconnected power system Elements that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults".
No
Hydro One believes 60 months is a more appropriate time frame to conduct, document and obtain consensus for a protection system study. This timeframe is also more in line with the timeframe proposed in the draft PRC-019-1 in Project 2007-09. Large entities and small entities have the same time frame to complete this work which seems unreasonable. Alternatively, an extended period should be provided based on a formula that factors the quantity of interconnected power system elements.
No
This change seems more ambigious than "reach agreement". How can changes to Protection Systems occur unless agreement is reached via a signed off Protection System Study? What does it mean to "confirm acceptance"?
Yes
Individual
Michael Moltane
ITC
Yes
No
The general idea of the Interconnected Element is acceptable. However, when one Registered Entity takes care of coordination between two Functional Entities, or coordinates all protection coordination between the two systems, the documentation will become onerous and not

enhance the reliability of the BES. The definition of the Protection System Study still needs further clarification. It is not clear what calculations/documentation must be kept to properly demonstrate compliance with the requirement of a "study." Past practice may have kept calculations and correspondence, which adequately demonstrate "evidence of coordination," but might or might not be adequate to a "protection system study" for future coordination efforts.
No
The amount of work required to comply with this requirement may be significant and may impact ongoing efforts to upgrade and improve the system. The above items that need to be documented can often be discussed and agreed to verbally between parties and are were often not part of a permanent record. The additional record keeping required may be significant and not add to the reliability of the BES.
Yes
Yes
Figures 1-5 designate a preferred responsibility of coordination on either entity which contradicts with intent of R3. R3 details all the changes which must be provided to the adjacent utility, seemingly so they can coordinate their protection over yours. However, Figures 1-5 place the coordination responsibility on the utility which does not own the Protection System. I agree that R3 should remain almost as-is. However, the coordination responsibilities in Figures 1-5 should be reversed or preferably removed. Owner R should be responsible for coordinating Breaker A relays. Only the owner should be responsible for coordinating this relay. SDT needs to define the term "interconnecting bus" and perhaps identify the interconnecting bus in Figures 1-5. In Figures 1-4 the Interconnected Element is a line.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We agree with the purpose statement, but suggest to add "settings" after protection system (with the "s" removed") to make it clear that it is the coordination of the settings, not the design of protection systems.
No
The definition of Interconnected Element is confusion since there is a mixture of Functional Entities and Registered Entities, and some in the industry equate Functional Entities to Registered Entities. To avoid this confusion, we suggest to replace Functional Entities with asset owners or facility owners. If deemed desirable, the asset owners can be qualified by Transmission Owners, Generator Owners and Distribution Providers in parentheses
Yes
Yes

We agree with the intent of the proposed changes, but believe some editorial changes are necessary for more clarity. We suggest the following wording for the SDT's consideration: "Confirm with the owner(s) of each Facility associated with the affected Interconnected Element that it accepts (or acceptance of) the resulting Protection System(s) changes." In fact, Part 4.1 could also be worded to add clarity: "Within 90 calendar days after receipt of the proposed Protection System(s) changes,"
No
(1) We do not have a strong view one way or the other with respect to "provided" versus "demonstrating". However, the wording used among Measures needs to be consistent. For example, in M1 the wording is "Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1. and 1.1.2, and 1.1.3 is a dated Protection System Study, or the summary results of…" seems reasonable since it shows the examples for "acceptable evidence". The examples listed illustrate what constitute "acceptable evidence". However, in M2, the wording "Acceptable evidence for Requirement R1, Part 1.2 demonstrating that the summary results of each Protection System Study (hard copy or electronic file formats) was provided…." Does not illustrate what constitutes "acceptable evidence", thereby leaving that to interpretation. We suggest M2 (and M4) be reworded along the same line as that for the other Measures (M1, M3, M5 to M9). (2) The Comment Form does not have a question on "Do you have any other comments?" Therefore, we are submitting the following comment under this Question. We reiterate our concerns previously expressed with respect to PRC-001: We do not agree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. If this is a training requirement, it should be transferred to the appropriate PER standards. c. Measures M1 is removed from the standard. This does not conform with the Elements of a Reliability Standard template, specifically those specified in the "Mandatory and Enforceable Sections of a Standard". d. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. However, leaving this not measurable and unnecessary requirement in PRC-001-3 is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT could have proposed a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee's advice/direction for appropriate actions. The SDT's response to our previous comment was "This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff." We do not believe that the staff has brought this to the Standards Committee's attention. Note that the Standards Committee is responsible for managing the standards development process and as such, can make an informed decision to either request the SDT to expand its scope (via an amended SAR) to address the PRC-001 issue, or to ask staff or the SDT to prepare a separate SAR to address the issue in parallel.

Leaving the PRC-001 hanging out there without a recourse is not a satisfactory solution, and may in fact harm reliability. Once again, we urge the SDT to take the initiative to bring this issue to the Standards Committee, with a proposal to amend the SAR or prepare a new SAR, or seek its advice and direction before continuing work on this project.
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst abstains and offers the following comments for consideration: 1. Requirement R1, Part 1.1.1 a. ReliabilityFirst questions the rationale for the 48 calendar month window to perform a Protection System Study if NO study exists. ReliabilityFirst believes that a Protection System Study is one of the fundamental reasons for the standard and believes if NO study had ever been performed, one should be performed as soon as possible (12 months). Within the rationale section, the SDT states: "The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame." With no widespread mis-coordination of protection systems, ReliabilityFirst questions the actual need for the standard itself. 2. It is not clear where the 10% threshold in Part 1.1.2 and calculated in Part 2.1.2 is applied. Does the 10% threshold apply to the total bus Fault current at the interconnecting bus or the contributing Elements? If it is the total, then there are situations where some of the sources into the bus may change their contribution quite a bit more than the 10% threshold but yet the total change could be less than 10%. Protective relaying is set in reference to the Element it is protecting or, to be more precise, the instrument transformers associated with an Element. The 10% threshold should be applied to the Interconnecting Element as its contributing quantities could change significantly even if the total Fault current stayed nearly the same. It is the Fault quantities on the Element that the interconnection protection sees – not the total bus Fault current (unless the Interconnecting Element is a bus). It is also not clear which phase or sequence currents are being used in the %Deviation calculation. Is it 3I0 (3 times zero sequence) current for single line to ground Faults and I1 (positive sequence) current for 3-phase Faults? It should be noted that if variations in Fault current of 10% are acceptable, then entities may need to adjust their criteria to use margins of 15% or more to consider other sources of error such as relay and instrument transformer accuracy.
Yes
ReliabilityFirst abstains and offers the following comments for consideration: 2. Requirement R4 Violation Severity Level a. During the previous comment period, ReliabilityFirst recommended that VRF for R4 be changed to "High" since this is dealing with interconnection protection systems. The SDT response by indicating they "…believes the VRF for Requirement R4 more aligns with the NERC criteria for a medium risk. " After reading the NERC criteria for a medium risk, ReliabilityFirst would agree only if the Time Horizon of this requirement is

changed to “Long Term Planning”
ReliabilityFirst offers the following comments on the VSLs for consideration: 1. Requirement R3 VSL a. ReliabilityFirst believes VSL for Requirement R3 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement.” Requirement R3, Part 3.1 and 3.1 requires the entity to provide “details” and the associated VSLs references “information”. ReliabilityFirst recommends the SDT modify the VSL to be consistent with the language in the requirement. b. It is unclear which requirement the last VSL under the “Severe” category is referring to. ReliabilityFirst recommends adding the Part number in which the VSL is associated with. 2. Requirement R4 VSL a. ReliabilityFirst believes VSL for Requirement R4, Part 4.1 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement.” The VSLs associated with Part 4.1 use the language “confirmed acceptance” though the language in the actual Part talks about review of summary results and response as to whether further action is required. ReliabilityFirst recommends the SDT modify the VSL to be consistent with the language in the requirement as follows: “The responsible entity reviewed the summary results of a Protection System Study and responded as to whether further action is required per R4, Part 4.1, but was late by 10 calendar days or less”
Individual
Jonathan Meyer
Idaho Power Co.
Yes
Yes
Yes
Yes
Yes
R1 The requirement is written to be applicable to Transmission Owners. In our case we have several lines where we do not own the Interconnecting Element, but operate the Protection System at one terminal. Based on the Glossary, we believe this makes us a Transmission Operator. If this interpretation is accurate, there would seem to be a gap in the Applicability of the Standard, as it does not include the Operator. R2 We are wondering why this Requirement is only applicable to the Transmission Owner. Should it not be applicable to all the functional entities similar to the language used in R1, R3, and R4? General comments In reviewing the Standard, there was confusion related to the Protection System Study and what the 10% was measured against. We believe that the Protection System Study referred to in the Standard is that group of faults and contingencies used to create the in-service settings of the relay. Could this be clarified? Additionally, the exchange of information between Functional Entities is a

critical part of PRC-027, however, no mechanism is in place to ensure proper contact information is available. Employee movement within a utility may render contact information obsolete. In addition, Independent Power Producers, such as wind farms, are not typically staffed by local personnel or by individuals with a knowledge of System Protection. Because PRC-027 relies so heavily on the exchange of information it is not sufficient to simply place time lines on the transfer of data between Functional Entities. Additional controls to ensure that these data requests reach the appropriate people is needed.
Individual
Brian Murphy
NextEra Energy
No
See page 19 of the redline PRC-027 Guidelines and Technical Basis. " System condition used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions." Please clarify that "single contingency conditions" refers to breaker failure or protective system failure. It is not intended to mean single contingency operating conditions such as line or transformers out of service.
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes
No
Clarification is necessary for the definition of "Interconnected Element" which requires the TO and GO function within a company to treat each other as if they were unrelated entities and apply all of this standard's requirements.
No
"The results based objective is that the registered entities communicate and coordinate with each other. A simple statement by both entities that they have reviewed each other's settings and agree they coordinate is sufficient proof that the reliability objective of this standard is met." Performance of a PSS is an intermediate step toward achieving coordination. It does not improve reliability if an entity does not act on it. Only in the final step – when agreed upon changes are made – does system reliability actually improve. The standard should consist of R3.1 (one side makes a change which triggers a review), followed by R4.2 (all parties agree to

the changes to be implemented). Documenting the process steps between these two points in time does not improve system reliability.
Yes
Yes
Although this is unrelated to Question 5 there was no other space allocated for the for “any other comments.” While this is most likely a clerical error, we feel it is not appropriate to post a standard without making such a question available.
Individual
Saul Rojas
New York Power Authority
Agree
NPCC
Group
seattle city light
paul haase
Yes
No
Seattle City Light does not agree with the use of Functional Entity in the definition of Interconnected Element. Seattle has several objections. First, although “Functional Entity” is capitalized in the draft Standard, this term is not defined in the NERC Glossary of Terms. A second objection is that “Functional Entity” in this role does not add clarity to the Standard. “Functional Entity” is defined in the NERC Reliability Functional Model as “the term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function.” This definition refers to other terms defined only with the Functional Model document (“Task,” “Function”). It is not illuminating as to defining the bodies joined by Elements. The third and strongest objection is that use of the term “Functional Entity” in the proposed definition is incorrect and inconsistent with the NERC Functional Model, and as such creates confusion about Standard obligations for entities registered for more than one function. The NERC Functional Mode Version 5 (November 30, 2009) explicitly does not require any particular organization or assignment of functional Tasks or ownership of Elements for any multi-function entity. Functional tasks and Elements exist undifferentiated across an entity as a whole, and the NERC Functional Model document states clearly that no further differentiation is expected, required, or implied. (See, for example, p. 7 “The Functional Model describes a functional entity envisioned to ensure that all of the Tasks related to its Function are performed. The Model, while using the term ‘functional entity’, is a guideline and cannot prescribe responsibility” and p.8 “The Model is independent of any particular organization or market structure.”) Seattle City Light, for example, is a vertically integrated municipal utility registered for 11 functions: BA, DP, GO, GOP, LSE, PC, PSE, RP, TO, TOP, and TP. Registration is

made without differentiation: no particular sub-organization within Seattle City Light is identified as owning GO Elements, TO Elements, and so on. The Model is simply that Seattle City Light or any other multi-function entity owns a set of Elements s a unit. By contrast the draft definition relies upon differentiation of ownership of Elements within a multi-function entity, so that it can be determined if the proper studies were undertaken or not. Such differentiation is outside the Model and introduces complexities and unintended consequences not envisioned by the Functional Model and the term “Functional Entity.” The same confusion about the term Functional Entity occurs in draft Standard COM-003-1. Seattle suggests that NERC immediately clarify the use of this term. Until the definition of the Functional Model is changed and changed significantly, the use of Functional Entity to define obligations within a Standard or definition (other than in the Applicability section) should be eliminated. As is it is simply a misreading, tempting as it may be, to presume that Functional Entity Tasks are assigned with greater granularity than to an organization as a whole. And it is a misreading that does not promote high quality Standards that can be consistenly enforced across auditors and across regions. You can do better, and should do better. Seattle apologies that it does not have a suggested fix at this time, because the Functional Entity approach is so fundamentally wrong. Entitly new wording would be required to capture Elements existing within the same registerd Entity.
Yes
Yes
No
Because there is no "other comments" section included in this comment form, the following comments about the timelines for specific actions are appended here. (R3.2) "Data Requests . . . . 30 Days or agreed to schedule' Seattle requests that "agreed to schedule" be clarified, in particular the limits in determing this schedule. If no further clarity is added, Seattle suggests that "or agreed to schedule" simply be deleted. (R2.1) Short Circuit Study . . . . . . 24 months SCL recommends that the time line of 24 months be removed and that the 10% change in fault current criteria serve as the replacement for this requirement. (R4.1) "Review PS Study . . . . .90 Days or agreed upon schedule" Seattle is concerned that, depending upon the complexity of the study, a lot of back and forth communication between the utility entities may be required. Please clarify 1) if each response to, or revision of the study trigger another 90 day review period and 2) the limits as the defining an "agreed to schedule." If no further clarity is added regarding agreed to schedules, Seattle suggests that "or agreed to schedule" simply be deleted.
Individual
Stephanie Monzon
PJM Interconnection

PJM supports revising the language in Requirement 1 of PRC-001 by replacing the term ‘familiar.’ This word is ambiguous and confusing in terms of the specific expectations of the applicable functional entities regarding the purpose and limitations of protection system schemes applied in its area.
Individual
Eric Salsbury
Consumers Energy
The following comments are unrelated to Question 5. However, there has not been a question/section added for other/general comments. 1) In the process flow chart (page 22) the R2.2 box which states “Within 30 days, provide each owner of the Protection System associated with the Interconnected Element”, we believe the key element, “the updated Fault current values” was not included in this statement. 2) In reading the Example Process on page 23, we were expecting to be able to follow it through the process flow chart on page 22 as one possible example to guide you through the standard process. As it started off as a request for information, we assumed the flow process started in the R3 box “Data request” which indicates no further action. Yet the example process continues on. We would suggest an improved explanation paragraph be added to the “Example Process” to better clarify what the example is intended to illustrate.
Group
pacificorp
ryan millard
Yes
Yes
Yes
Yes
Yes

Individual
Richard Vine
California Independent System Operator
Agree
The California ISO is in support of, and has signed on with, the comments submitted by the Standards Review Committee (SRC) (ISO/RTO Council).
Group
FirstEnergy
Larry Raczkowski
No
In regard to the purpose statement, FirstEnergy supports the response submitted by the RFC Protection Subcommittee which is repeated here for convenience. The purpose should mirror the objectives of the Protection Systems Study. “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence.” The reasons being that an entity may choose to overtrip distribution transformer (non-BES) protection, to employ zone 1 extension schemes, or for other valid reasons trip more than the least number of Elements to clear a Fault.
No
FirstEnergy supports the proposed definition for Protection System Study but believes the Interconnected Element definition requires some modification. As presently written the Interconnected Element definition appears to inadvertently omit coordination of two transmission owners that have tie-lines to each others systems. The two transmission owners are not “separate Functional Entities” but rather two Registered Entities performing the same functional entity (transmission owner) obligations. Additionally, it is understood that the intent is to also require Protection System coordination at interconnection points where the point of interconnection may entail facilities owned by the same NERC Registered Entity having multiple functional entity classifications. FirstEnergy proposes the following definition for Interconnected Element “An Element that electrically joins and interconnects facilities owned by: a) separate Registered Entities, or b) the same Registered Entity, but includes multiple functional entity (DP, GO or TO) responsibilities.”
No
A) FirstEnergy supports the 48 month timeframe to complete initial Protection System Studies. However, based on the fact that the SDT may have overlooked system tie points of two transmission systems (see our response to Q2) the completion of Protection Studies may require additional time. FE could support a 48 month implementation and encourages the drafting team to consider a staggered plan that requires earlier completion for higher voltage systems. For example, 1) systems operated at 300kV and higher within 24 months, 2) systems operated at 200kV and higher up to 300kV within 36 months and 3) systems operated at 100kV and higher up to 200kV within 48 months. B) As expressed in FirstEnergy’s Draft 1 comments,

we do not support requirement text that is better placed in an Implementation Plan. A requirement should be written such that it is everlasting. As written, R1 part 1.1.1. has no meaning after the 48 month period expires. C) It is FirstEnergy's experience that the Transmission Owner would likely have the expertise and staff to perform the desired Protection System Study. The team should consider whether or not the DP and GO would typically be performing their own independent study or collaborating with the TO in a supporting role by providing data and reviewing study results. In regard to items B) and C) FirstEnergy proposes the following for Requirement R1. **Start of proposed requirement R1 text ** R1. Each Transmission Owner shall perform a Protection System Study for each Iterconnected Element on its System associated with a Generator Owner, Distribution Provider or another Transmission Owner. Each study shall include at a minimum: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning] • the protective relay settings reviewed • power system Elements to be isolated • contingencies evaluated • Fault currents used • any issues identified • any revisions proposed 1.1. Each Transmission Owner shall update its Protection System Study: 1.1.1 Within six calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. 1.1.2 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 or Part 3.3, or technically justify why such a study is not required. 1.2. Within 90 calendar days after the completion of each Protection System Study the Transmission Owner shall provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement. **End of proposed requirement R1 text ** FirstEnergy recommends that for ease of ordered reading that the numbering of Measures be tied to the Requirement number. For example Requirement R1 has two measures M1 and M2. Consider renumbering to M1.1 and M1.2.
No
FirstEnergy proposes that R4 Part 4.2 be deleted. The requirement is overly burdensome and R4 part 4.1 should provide sufficient evidence of whether or not the entity receiving study results believed any further action was required. Absent any such notification, the party would by default be accepting of the information. In regard to need for "acceptance" prior to planned changes FirstEnergy does not believe this is necessary. The drafting team in its rationale provided for Requirement R1 indicated "The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements" therefore we do not believe R4 part 4.2 is a necessary reliability requirement. Furthermore, other changes (R3 part 3.3) potentially trigger upgraded Protection System Studies being communicated without "acceptance" prior to their implementation.
Yes
FirstEnergy supports the change described by Question 5. Other comments from FirstEnergy in addition to the specific questions asked by the drafting team: A) PRC-001-3 EFFECTIVE DATE: The PRC-001-3 standard needs to be edited to match what is stated in the Implementation Plan. The Implementation Plan indicates that both PRC-027-1 and PRC-001-3 will become effective at the same time which is stated as being the first day of the first calendar quarter

that is six months beyond the date that this standard is approved by applicable regulatory authorities. However, the PRC-001-3 standard in its Effective Date section indicates the first day of the first calendar quarter twelve months following applicable regulatory approval. B) PRC-001-3 VERSION HISTORY: The Version History of the PRC-001-3 standard needs some clean-up. The table reflects a "version 4" however this project creates version 3. Looks like the fix is to delete the row labeled version 3 and change the version 4 to reflect 3. The description text in that row is correct. C) PRC-001 VERSION CHANGES: NERC needs to consider what it plans to do with the existing NERC BoT Approved versions PRC-001-1.1 and PRC-001-2 which have yet to be filed with FERC. It is recommended that NERC suspend the filing of those standards, keep it simple and file PRC-001-3 with this project. This will avoid undo industry confusion and transition. D) PRC-001-3 MISC CLEAN-UP: Section D, Part 1.1 revise Compliance enforcement authority" to read "Compliance Enforcement Authority (CEA)". This is a defined glossary term and is shown capitalized in other areas of the standard. In the second sentence, capitalize "entity" in the reference to "Regional entity". E) PRC-001-3 R1: Seems odd to have a standard with only one requirement. The requirement states "Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area." FE proposes that R1 or an alternate be moved to PER-005.
Group
Florida Municipal Power Agency
Frank Gaffney
No
The primary purpose of protection system coordination is to ensure faults are cleared expeditiously and well under the critical clearing time, with the stated purpose of minimizing the number of elements isolated as a secondary consideration, not a primary consideration. As such, there is no recognition of the importance of remote back-up protection that backs up primary and secondary protection, but, does not necessarily share the same goal of minimizing number of elements tripped, but, does share the goal of clearing a fault within the critical clearing time.
No
The definition of Interconnected Element limits the scope of the standard too much. The standard only requires coordination between neighboring entities and not of protection of other BES equipment within the same entity, e.g., one TO’s transmission line protection with the protection of another transmission line owned by that same TO is not within the definition of Interconnected Element. It would seem that such a requirement would be necessary, e.g., each entity ensures that their protection internal to their system coordinates with itself, and that they coordinate at the boundaries with its neighbors. That would ensure coordination across the BES. Protection System Study definition should have a time element and a consideration for the critical clearing time, e.g., “and demonstrates that the resulting clearing time meets or beats the clearing time used in studies to comply with the TPL standards” or something to that effect

No
As worded, R1 seems to require two neighboring entities to perform independent studies. We would hope that the intent of the SDT is to allow any one entity to do a study and then the neighboring entity accept the results of that study, or to perform a joint study. We suggest the SDT make conforming changes to allow this.
Yes
No
First, there should be an “any other comments” question. Seeing that there isn’t one, we are adding our other comments here. R3 – There should be thresholds of change to the bullets. For instance, changing the no-load tap changer of a GSU does minimally change the impedance of the GSU). A transmission line neighbor installing a long chain link fence along the ROW will have a minimal impact on mutual coupling. These minimal changes do not require redoing the study, so, what percentage change in impedance requires redoing the study?
Individual
John Bee
Exelon Corporation and its affiliates
No
Exelon agrees with the Purpose statement as stated, however the questions and layout of this comment form doesn't provide an area to provide comments as to why we are voting negative. While requiring periodic coordination studies between entities is laudable, it is unnecessary. The coordination of a protection system, by nature, is tested every time it operates. We already have a standard, PRC-004-2, that requires all transmission protection system operations to be analyzed for correctness and any misoperations reported, along with corrective action plans to mitigate their cause. Our experience indicates the bulk of protection system misoperations are not caused by a lack of coordination studies. This standard, as written, continues to be vague and will lead to an inconsistent application of the requirements. Most importantly, we believe this standard is ill advised. Coordination of protection systems between entities was not a factor in the 2003 blackout. As such it clearly goes beyond the mandate of the 2003 blackout recommendations. Implementation of this standard will add little to the reliability of the bulk electric system while adding substantially to the amount of time and money an entity spends simply on compliance activities. Contrary to the goal of enhancing reliability, this standard will simply dilute available resources to the detriment of reliability.
Yes
Yes
Yes

Individual
Don Schmit
Nebraska Public Power District
No
It seems the real purpose of this standard is “To coordinate BES Protection Systems for Interconnected Elements”. The rest of the statement is already covered as part of the protection systems design which will involve coordination or not depending on any special issues or existing design limits.
Yes
No
To mitigate compliance risks for various types of data formats for existing studies and studies older than June 2007 this standard will likely require utilities to go back and update all data so that it meets the requirements and description of evidence in the application guidelines when the requirements become enforceable. This could likely take longer than 3 years. I would recommend more time such as 6 years based on two audit periods (time depends on the number of applicable system ties as well).
No
Getting acceptance within the required time frame is not in the control of the requestor. The concern is the numerous timelines in this standard that require timely responses will create an overly complex standard that will be difficult implement and to audit. The starting points for the timelines will be difficult to audit as well since much of this must be determined between two or more entities. How will enforcement view a requesting utility that sends a timely request but the response is a late confirmation of acceptance? The numerous time lines will create significant confusion and very complex data retention practices that will be difficult to track and difficult to audit. It appears the focus is more on time lines and the likely result is the content of the shared information will likely suffer due to the burden of tracking dated communications between entities. This draft standard includes time lines ranging from “prior to in service date, 30 days, 90 days, 6 months, 2 years and 4 years”. There should be fewer and simpler time lines with the focus on if the sharing of information took place and not on when did it take place. The SDT statement below should be generalized to the standard as a whole: “The SDT believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the SDT sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable “prior to the in-service date,” At a minimum remove the calendar day references and make them all 6 months for simplicity so the option is to use and agreed upon time or 6 months. Possible Suggestions: A simpler method would be after the initial 4 years to perform a study then every

24 months perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the interconnecting bus per Requirement R1 and demonstrate that the fault model was provided to the interconnecting entities within this time period along with the settings so the receiving entity can review against their design. Auditing would verify this data was sent on a two year schedule. For new protection interfaces verify protection studies or relay settings or summaries of studies were exchanged for review prior to the equipment going in service.
No
Measurement 9 for R4 requires confirmation of acceptance prior to implementation of any planned protection system changes. This appears to be similar to ‘demonstrating that each affected entity received notification.’ The concern is holding one company responsible for actions of another that is not under the requestor’s control. It is recommended that there be clarification that if the requestor does not get confirmation of acceptance in the proper time line then the requestor is not accountable or subject to violations. Another option is to remove R4.2.
Group
Certain Members of the ISO RTO Council
Charles Yeung
No
Although the SRC agrees that protection systems should strive to interrupt only those elements closest in to a fault to avoid excessive interruptions, there are situations where it is necessary to trip elements beyond those that only interrupt the fault. To set a result for “…the least number of power system Elements are isolated to clear Faults” misses the primary goal for a reliability standard meant to protect the interconnected bulk electric grid. NERC standards should always have the underlying purpose to prevent cascading failures that affect interconnected systems. The stated Purpose must recognize that the “least number of power system Elements are isolated to clear Faults to maintain system integrity”. For example, a relay scheme could isolate a fault on a generator connected between two line terminals by opening the breakers on both ends of the line. This would fulfill the Purpose of “least number of power system Elements”, however, a protections scheme for that segment of transmission line may require that the next terminal along that line also be interrupted in order to prevent an unintended increase in load to a particular element due to the opening of the breakers closest to the fault.
No
The definition of Interconnected Element is confusing since there are a mix of Functional Entities and Registered Entities, and some in the industry equate Functional Entities to Registered Entities. To avoid this confusion, we suggest replacing “Functional Entities” with “asset owners” or “facility owners.” If deemed desirable, the asset owners can be qualified by Transmission Owners, Generator Owners and Distribution Providers in parentheses The SRC asks if the definition for “Interconnected Facility” needs to be expanded to include situations where a Functional Entity may cross regional boundaries and have facilities that interconnect

between the two, which may or may not be the same Registered Entity.
Yes
Yes
Yes
NERC must continue to correct such requirements, as it is not the responsibility of the entity subject to a requirement to ensure another party acts.
Group
FirstEnergy
Doug Hohlbaugh
No
In regard to the purpose statement, FirstEnergy supports the response submitted by the RFC Protection Subcommittee which is repeated here for convenience. The purpose should mirror the objectives of the Protection Systems Study. “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence.” The reasons being that an entity may choose to overtrip distribution transformer (non-BES) protection, to employ zone 1 extension schemes, or for other valid reasons trip more than the least number of Elements to clear a Fault.
No
FirstEnergy supports the proposed definition for Protection System Study but believes the Interconnected Element definition requires some modification. As presently written the Interconnected Element definition appears to inadvertently omit coordination of two transmission owners that have tie-lines to each others systems. The two transmission owners are not "separate Functional Entities" but rather two Registered Entities performing the same functional entity (transmission owner) obligations. Additionally, it is understood that the intent is to also require Protection System coordination at interconnection points where the point of interconnection may entail facilities owned by the same NERC Registered Entity having multiple functional entity classifications. FirstEnergy proposes the following definition for Interconnected Element: "Interconnected Element - An Element that electrically joins and interconnects facilities owned by a)separate Registered Entities, or b) the same Registered Entity, but includes those representing multiple functional entity (DP, GO or TO) responsibilities."
No
A) FirstEnergy supports the 48 month timeframe to complete initial Protection System Studies. However, based on the fact that the SDT may have overlooked system tie points of two transmission systems (see our response to Q2) the completion of Protection Studies may require additional time. FE could support a 48 month implementation and encourages the drafting team to consider a staggered plan that requires earlier completion for higher voltage systems. For example, 1) systems operated at 300kV and higher within 24 months, 2) systems

operated at 200kV and higher up to 300kV within 36 months and 3) systems operated at 100kV and higher up to 200kV within 48 months. B) As expressed in FirstEnergy's Draft 1 comments, we do not support requirement text that is better placed in an Implementation Plan. A requirement should be written such that it is everlasting. As written, R1 part 1.1.1. has no meaning after the 48 month period expires. C) It is FirstEnergy's experience that the Transmission Owner would likely have the expertise and staff to perform the desired Protection System Study. The team should consider whether or not the DP and GO would typically be performing their own independent study or collaborating with the TO in a supporting role by providing data and reviewing study results. In regard to items B) and C) FirstEnergy proposes the following for Requirement R1. **Start of proposed requirement R1 text ** R1. Each Transmission Owner shall perform a Protection System Study for each Iterconnected Element on its System associated with a Generator Owner, Distribution Provider or another Transmission Owner. Each study shall include at a minimum: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning] - the protective relay settings reviewed - power system Elements to be isolated - contingencies evaluated - Fault currents used - any issues identified - any revisions proposed 1.1. Each Transmission Owner shall update its Protection System Study: 1.1.1 Within six calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. 1.1.2 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 or Part 3.3, or technically justify why such a study is not required. 1.2. Within 90 calendar days after the completion of each Protection System Study the Transmission Owner shall provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement. **End of proposed requirement R1 text ** FirstEnergy recommends that for ease of ordered reading that the numbering of Measures be tied to the Requirement number. For example Requirement R1 has two measures M1 and M2. Consider renumbering to M1.1 and M1.2.
No
FirstEnergy proposes that R4 Part 4.2 be deleted. The requirement is overly burdensome and R4 part 4.1 should provide sufficient evidence of whether or not the entity receiving study results believed any further action was required. Absent any such notification, the party would by default be accepting of the information. In regard to need for "acceptance" prior to planned changes FirstEnergy does not believe this is necessary. The drafting team in its rationale provided for Requirement R1 indicated "The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements" therefore we do not believe R4 part 4.2 is a necessary reliability requirement. Furthermore, other changes (R3 part 3.3) potentially trigger upgraded Protection System Studies being communicated without "acceptance" prior to their implementation.
Yes
FirstEnergy supports the change described by Question 5. Other comments from FirstEnergy in addition to the specific questions asked by the drafting team: A) PRC-001-3 EFFECTIVE DATE: The PRC-001-3 standard needs to be edited to match what is stated in the Implementation

Plan. The Implementation Plan indicates that both PRC-027-1 and PRC-001-3 will become effective at the same time which is stated as being the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. However, the PRC-001-3 standard in its Effective Date section indicates the first day of the first calendar quarter twelve months following applicable regulatory approval. B) PRC-001-3 VERSION HISTORY: The Version History of the PRC-001-3 standard needs some clean-up. The table reflects a "version 4" however this project creates version 3. Looks like the fix is to delete the row labeled version 3 and change the version 4 to reflect 3. The description text in that row is correct. C) PRC-001 VERSION CHANGES: NERC needs to consider what it plans to do with the existing NERC BoT Approved versions PRC-001-1.1 and PRC-001-2 which have yet to be filed with FERC. It is recommended that NERC suspend the filing of those standards, keep it simple and file PRC-001-3 with this project. This will avoid undo industry confusion and transition. D) PRC-001-3 MISC CLEAN-UP: Section D, Part 1.1 revise Compliance enforcement authority" to read "Compliance Enforcement Authority (CEA)". This is a defined glossary term and is shown capitalized in other areas of the standard. In the second sentence, capitalize "entity" in the reference to "Regional entity". E) PRC-001-3 R1: Seems odd to have a standard with only one requirement. The requirement states "Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area." FE proposes that R1 or an alternate be moved to PER-005.
Individual
Mike Hirst
Cogentrix Energy Power Management, LLC
No
The purpose is laudable, but the means by which it is to be achieved needs more work. The Application Guidelines section of PRC-027 makes reference to, “the entity performing the Protection System Study [for R1],” but the standard provides no indication of who this should be. This responsibility is simply assigned to, “Each Transmission Owner, Generation Owner, and Distribution provider.” The obligation placed on GOs by use of the word “each” in R1 cannot be fulfilled, however, except under the circumstance of having a vertically-integrated utility. An independent GO does not have knowledge of the TO’s system, and in a deregulated market is not allowed to have such knowledge. The TO and TOP are provided with detailed information of the GO’s equipment, however, and therefore perform all interconnection-related studies. This is as it should be, because changes in the transission don’t matter to a GO. We do not modify our Protection Systems in response to changes to the Fault current at an interconnecting bus, we just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Everything involving sequencing the tripping of multiple Elements is in the TO’s system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e. reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-

scale wind farms) need to be included in PRC-027 the standard should address that specifically. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performend by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.
No
The term Functional Entity needs a definition. It is capitalized in PRC-027 but is not defined in the standard or in the NERC Glossary. It is nonetheless evident that a GO and TO are different Fnctional Entities, but the nature of the Element that joins them and thereby constitutes the Interconnected Element is unclear. Is this the transmission line? If so, would the TO be responsible for the R1 study if the ownership scope of an independent GO ends at the high-side terminals of the GSU or at an HV disconnect switch? Would the responsibility be shared if, as sometimes happens, the ownership split occurs at the fenceline, leaving a small part of the transmission line the property of the GO while the rest belongs to the TO? The definition of a Protection System Study needs to include identification of the party responsible for performing this work. This cannot be the GO if dealing with a deregulated market; since, as explained above, such parties are not allowed access to information about the TO's system.
No
The time frame is not the issue. R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.
Yes
Yes
Individual
Marie Knox
MISO
Agree
MISO supports the comments submitted by the Standards Review Committee (SRC).
Individual
Jim Cyrulewski
JDRJC Associates
Agree
Midwest ISO
Group
Tennessee Valley Authority
Dennis Chastain
Yes

Yes
No
We do not feel like 48 months is a reasonable timeframe to meet the minimum requirements for Protection System Studies (PSS). In the current form of the standard, for an existing PSS to be valid, several minimum requirements are given in R1.2. While this is a good requirement for new PSS, it eliminates almost all of our existing PSS as being valid. We have the stance that many of our existing PSS are of a high quality and should be considered valid, but do not meet the minimum requirements from R1.2. We recommend allowing existing PSS to be submitted in their current form between all protection system owners of an Interconnected Element within a reasonable time frame of the standard effective date and allowing the owners to approve the existing PSS as valid if they desire. Then, that existing PSS could be used as the baseline PSS until the 10% change in fault occurs from the existing dated PSS. At that time, a new PSS should be performed to meet the minimum requirements as outlined in R1.2.
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
No
The purpose of this study should be “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the proper sequence.” The least number of Elements to clear a Fault may not always be the case for some Protection Systems. The TO and TOP are provided with detailed information of the GO’s equipment and therefore perform all interconnection-related studies. Independent generators do not modify Protection Systems in response to changes to the Fault current at an interconnecting bus, generators just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Equipment involving sequencing the tripping of multiple Elements is in the TO’s system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e., reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should specifically address those GOs, rather than pulling in all GOs. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performed by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.
No
As per this version, the standard’s protection study requirement seems excessive. The

definition of a Protection System Study needs to include identification of the party responsible for performing this work, which should be the TO for the reasons discussed above.
No
Sixty months would be more appropriate to study all the interconnections. There has not been a major problem with mis-coordination of Protection Systems associated with Interconnected Elements. Also, the standard does not fully address what all should be included in a Protection System Study. R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.
Yes
There is no clear responsibility in the standard if both parties cannot confirm acceptance.
Yes
Individual
Clay Young
SCE&G
No
SCE&G disagrees with the definition of “Interconnected Element”. More clarity is needed regarding the language “Functional Entities that are part of the same Registered Entity”. Entities that are vertically integrated and more specifically those vertically integrated companies that that have the same personnel performing the review of protection systems for the function of the TO and GO could be unnecessarily burdened if the definition were misconstrued to the point of requiring these personnel to display evidence of comparing studies with themselves.
Individual
Daniela Hammons
CenterPoint Energy
No
CenterPoint Energy believes the purpose should use wording similar to that being proposed for the definition of “Protection System Study” instead of developing and utilizing different wording for the purpose statement. CenterPoint Energy recommends the purpose be stated as follows: “To coordinate Protection Systems for Interconnected Elements, such that Protection Systems operate as desired for clearing postulated short circuit Fault events.”
No

CenterPoint Energy recommends the term “Protection System Study “ be defined as follows: “A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing postulated short circuit Fault events.”
No
(a) CenterPoint Energy continues to believe a requirement to have a documented Protection System Study for each existing Interconnected Facility is overly burdensome, unless certain – if not all – existing Interconnected Facilities are exempted; therefore, CenterPoint Energy recommends R1.1.1 be eliminated from PRC-027-1. CenterPoint Energy does not believe a reliability need has been identified to justify that such prescriptive requirements are needed to provide for an adequate level of reliability. The following is stated on page 18 of 28 in PRC-027-1 Draft 2: “records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” The majority of existing Interconnected Facilities have fault-proven, time-proven protection system set points. An existing Interconnected Facility without a documented Protection System Study will eventually be included in a study with system additions and changes, short circuit current increases, and relay panel replacement projects, as well as any analysis of misoperations. (b) While an option has been included in Draft 2 R1.1.3 to allow for a technical justification why a study is not required for certain changes, CenterPoint Energy believes that reasonable thresholds should be established for the changes identified in R3.1. For example, R3.1 requires that “any” change of sequence or mutual coupling impedance must be provided to a Generator Owner. For insignificant changes of sequence or mutual coupling impedance, CenterPoint Energy believes there would be little, if any, reliability benefit of communicating and technically justifying why a study is not required.
No
Providing schedule information and project details by a transmission service provider to a generation entity may be governed by established, regional market rules that provide for what information can be shared with competitive entities. There are many installations in the ERCOT System where the owner of the interconnecting switchyard is not the same entity as the owner of the interconnected generation facility.
Individual
Greg Davis
Georgia Transmission Corporation
Yes
Based on the SDT response to our Draft 1 comment regarding the use of ‘coordination’, we understand ‘coordination’ in the Title and Purpose to mean the technical aspect of relay coordination.
Yes
No

Guidelines and Technical Basis Req. R1: "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults."... ...These studies may include graphical coordination....; relay scheme simulation studies....; and sensitivity studies using sequence...., and adequate directional polarizing quantities. This activity will be onerous without a full system model and software to perform studies that would check coordination of stacked curves and stepped distance relays. Of particular note is the question of adequate directional polarizing quantities. There should be an expected minimum requirement such as time overcurrent plots and zone distance plots of the existing relay settings for the terminal with the fault points used as the basis. This data would then be used to indicate if the 10% point has been reached that would require a new coordination follow up at the end of the next 24 month fault study.
No
1) The protection criteria and philosophies between entities can differ. For example, one entity may use the practice of coordinating for normal and single worst case contingency conditions, which is included in information/documentation provided to the neighboring entity in such Protection System Studies. The neighboring entity may have a slightly different protection criteria or philosophy, so exceptions may be required on a case by case basis using the “art and science” of protective relaying. Therefore, interpretation of ‘confirming acceptance’ means there may be differences in protection elements used by each entity but that there were no major disagreements and that generally the methods were acceptable and included using industry protection practices. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance.
Yes
Other comments are being provided which could not be addressed in question 1 - 5 listed above: 1). R2 requires short circuit study every 24 months even though the SDT’s own rationale is that other requirements will trigger Protection System Studies first. Thus R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. 2). Please replace “detect Faults on the BES Transmission System” with “protect the BES Transmission System” in all three places it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 3). VSL escalation in 10 days is not representative of the severity of the violation. The SDT correctly points out in R1 rationale that it “has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements.” Many entities have numerous Interconnected Elements, and recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity’s Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels,

respectively. Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation. 4). Throughout the 1st and 2nd draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.1.1, R2.1.2, R2-2.2, R4-4.1, R4-4.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. We appreciate the Drafting Teams perspective, but the SERC PCS believes that such cross references are confusing. 5). Under R1 – MI measure wording does not read as a completed statement. Suggest removing 'that' from the first sentence. 6) The process chart is a direct indication that this process and undertaking for entities will be overwhelming. New systems will be required to track many details of timeframe requirements and communication dates. Additional resources will be required placing increased workload for an effort to change the process that already works for us when working with other entities. The Drafting Team indicated, 'there is no evidence there is widespread miscoordination of protection systems.'
Individual
Scott McGough
Georgia System Operations Corporaton
Agree
Georgia Transmission Corporation
Group
Duke Energy
Greg Rowland
Yes
The Purpose statement could be improved by striking the phrase "least number of power system Elements are isolated to clear Faults", and inserting the following phrase from the definition of Protection System Study: "Protection Systems operate in the desired sequence for clearing Faults". Some entities may choose to "over-trip" for certain Faults.
Yes
The SDT should consider putting the definition of Interconnected Element in the NERC Glossary.
Yes
Yes
Yes
Additional comment: R2.1.1 refers to "maximum available Fault current values", but it's unclear from the requirement or the Guidelines and Technical Basis how "maximum" is defined. We believe it should be maximum generation and all Facilities in service.

Group
JEA
Thomas McElhinney
No
Seems like Interconnect element is too broad and not enough clarity on what a protective system study requires (Ie, is this a setting coordination study? Redundancy studies? Dynamic studies? Duplication of TPL requirements.
Yes
There is no place to put in a comment for R2 so this is for R2. We believe that the requirement to perform an analysis should be changed from once every 24 months to once every 36 months. Whenever changes are done to the system an analysis is done so this for areas that have not changed and we believe that once every 3 years should be sufficient.
Yes
Yes
Individual
Brett Holland
Kansas City Power & Light
No
The reliability objective of this standard should be to insure that there is an agreement between two interconnected entities of relay protection schemes and relay protection settings for the interconnected facilities. This is achieved if there is documentation stating that the Interconnected operating companies have reached agreement on protection schemes and protective relay settings. This standard should only require documentation that neighboring owners are talking and agreeing with one another in relation to protection and control. The purpose in the draft standard makes it appear that you are in violation of this standard any time the system has a misoperation because of relay setting regardless of whether both parties have agreed on the settings used, but the measures tend to measure agreement with the other entity. PRC-004 is the standard for misoperation reporting and misoperation mitigation.
No
At our company there is one engineering group doing Protection System Studies for all Functional Entities and for multiple Registered Entities. Reliability is not enhanced by requiring a single engineering group to document and be audited for coordination with itself. An Interconnected Element should be defined as an element that electrically joins facilities that are controlled by separate operating companies and Protection Studies are done by separate engineering groups.

No
Proposed Requirement R1 allows 48 months to do an initial study with the explanation that there is no evidence of widespread miscoordination. We agree that there is no evidence of widespread miscoordination and therefore 60 months is the proper time frame for an initial study. We have also noticed that there is no question on this comment form for any other comments not addressed by the drafting teams questions. As such we note here that Requirement R1, 1.1.2 lists a 10% change in current as an action point. This implies that a 10% decrease requires action. We do not agree with this since most Protection Studies are done with all generation on. Most of the year all generation is not on with the result that normal operating conditions result in fault currents that are 10% below the maximum used in the Protection System Study. We also disagree with action required for a 10% increase in fault current since our standard relay settings no longer trip for instantaneous ground over current elements and the standard does not allow an entity to state a reason not to run this study or perform the calculations. When we did utilize instantaneous ground over current elements we allowed a 40% margin. We utilize other high speed protection elements not directly affected by changes in fault current. We recommend at least a 20% change in fault current to require action per this standard. Requirement R2 requires that a short circuit study be done every 24 months. As noted above 60 months is proper time for initial study and is also proper for subsequent studies done after the initial study is complete.
Yes
Yes
Group
Western Electricity Coordinating Council
Steve Rueckert
We agree that unnecessary power system Elements should not be isolated to clear Faults, but question the statement that the “least number of power system Elements should be isolated.” Reliability should be the goal. There may be situation where different isolation schemes both work, but perhaps one that isolates one or two more elements is more reliable.
Yes
We agree with the definitions, but question the appropriateness of development of terms for a specific standard. Individual Regions are strongly discouraged from defining terms that only apply in a single region. We see the development of a term that is only applicable to a single standard to be a similar situation, leading to a proliferation of terms. If this approach is acceptable to NERC and FERC, we have no concerns.
No
Creating a Protection System consists of conducting Protection System studies and incorporating the data into an entity’s transmission/generation/distribution system. Protection System studies are not a new concept to entities. In the event that an entity discovers that

certain interconnected elements are not included in the Protection System study the entity should not require 48 months to make the needed changes to the study. From a reliability perspective, entities should already have a basic Protection System study in order to have a Protection System. Allowing an additional 48 months creates a potentially large 4 year reliability gap based on entities existing studies and any needed corrections. From a compliance perspective, allowing a 48 month time frame for entities to have a documented Protection System study effectively pushes mandatory compliance for this standard out for an additional four years beyond the effective date. This time frame is excessive and should be reduced to no more than 24 months from the effective date of the standard.
Yes
Yes
Individual
Angela P Gaines
Portland General Electric Co
No
Portland General Electric Company appreciates the drafting team's consideration of comments. Since there wasn't a general comment section at the end of this form, the discussion of timeframes seems appropriate here. The effective date (the first quarter six months after approval) does not allow sufficient time for compliance. This standard will require that entities include in all interconnection agreements a detailed protection coordination schedule or be subject to the long timelines detailed in the standard. None of the agreements (if they even exist) for projects six months out include a protection coordination schedule, nor do their project schedules accommodate the long durations detailed in the standard. Agreements will also need to be drawn up for smaller projects in order to document a protection coordination schedule, lest the interconnecting utility prevents us from energizing by taking the full 90 days to review the relay settings. In addition, entities may need at least one additional resource to conduct the bi-annual coordination studies and manage the interconnection due dates. PGE suggests an implementation period of 24 months since planning is done more than a year in advance.
Individual
Alice Ireland
Xcel Energy

Yes
Yes
Yes
No
Requirement 4.2 requires entities to receive evidence confirming acceptance of changes prior to implementing these changes. This coordination already occurs, and we believe this should be a standard practice for all applicable entities. However, we do not agree that this documentation-only requirement is necessary or beneficial to reliability. Instead, we believe this would deter valuable resources to unnecessary compliance evidence activities. Therefore, we recommend that this requirement be eliminated.
No
Since the SDT did not provide a question for “any other comments”, Xcel is using this question for that purpose. 1) We would appreciate some additional clarity as to what transmission fault conditions need to be evaluated by the Generator Owner. Figure 2 does not apply to very many of our units (on most, Breaker A would not exist and Breaker C is part of a breaker-and-a-half scheme). Is the generator supposed to evaluate only faults on the line between the GSU Transformer and the substation or evaluate his protection settings for a fault on any of the transmission lines leaving the substation? Can the drafting team, either as part of the Application Guideline or in a separate document provide a list of protective functions the Generator Owner needs to evaluate or is it the complete suite of protective functions defined in the NERC SPCS Generator – Transmission Protection Coordination Guideline? 2) Requirement 3.1 is onerous as it requires notification for an open ended “when the proposed change modifies the conditions used in the coordination of Protection Systems.” The requirement should be limited and instead provide a simple list of element changes that generally affect coordination with adjacent Elements. 3) Similarly for 3.3, we recommend that this be modified to limit the scope to only changes that result in a change of performance or ratings. For example, settings that change the alarm conditions for a device or a “like-for-like” replacement should not be required to be communicated. Communicating every change would not improve reliability and would instead deter valuable resources to unnecessary compliance evidence activities.
Individual
Karen Webb
City of Tallahassee
Yes
Yes

No
These phrases do not appear to be contained within draft two.
Yes
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing
Individual
Rich Salgo
NV Energy
No
Concerned that the Applicability and Purpose are encroaching upon Distribution elements, outside the statutory authority of the NERC Standards process
Yes
Yes
Group
Southern Company
Antonio Grayson
Yes
Yes
No
For large entities with hundreds of generators, a longer initial time frame is needed. In addition, consideration should be given to the fact that existing transmission protection and control engineering personnel will be fully engaged in the work associated with FERC order 754 for The next 12+ months.
No
The parties at the opposite ends of an interconnecting facility may not have the same

protection philosophies, and acceptance may not be achievable. It is unclear what it means to confirm acceptance. Does this mean that the two must come to an agreement for each other's protection system settings, or is it acceptable to agree that we disagree?
Yes
We believe that the proposed standard is too prescriptive regarding the specific duties and multiple time frames of each of the parties TO,GO, and DP. Including time frames for each Interconnect Element with regard to effective dates (6 mo), initial studies (48 mo), studies triggered by change of equipment or change of fault current (6mo), TO/GO/DP agreed upon schedules (variable), delivery of studies (90 days) , short circuit studies (24 mo), notification to others of fault current changes (30 days), change detail notification (30 days), and review of summary results (90 days) is unnecessary and unduly burdensome. The process flow chart provided on page 22 of the draft standard is evidence of the complexity of the proposition. Please seriously consider the following simplified three-requirement approach which will similarly accomplish the desired outcome of coordination of the Protection System for Interconnected Elements. R1). Require the two parties of the Interconnecting Element to jointly develop a Protection System Study- initially with X months to complete. R2). Require a review/update of the protection system study for proper coordination anytime a change to the system may upset coordination. R3). Require a review/update of the protection system study for proper coordination every X years. The corresponding measures for each proposed requirement could be... M1: has a protection system study been performed by the initial required date? M2: has a protection system study been reviewed/updated for system changes which impact the coordination? M3: has the protection system study been reviewed/updated every X years? During an audit period these requirements and measures will drive entities to establish and maintain protection system studies. This approach keeps the focus on the protection system study rather than the multiple actions with varying time frame restrictions. We believe that these changes will result in an equally effective driver to establish coordination while keeping the standard as succinct as possible.

Additional Comments:

ATCO Electric (AE) – Requirement R1.1.2 – A 10% change in fault current isn’t much in some areas of AE’s system, perhaps as little as a few hundred amps. This could lead to a burdensome requirement to frequently review the same areas of our system. Ten percent seems fairly restrictive when we typically use safety margins of 40% to 50% in selecting instantaneous overcurrent settings

Southern Company – In general, for protection on the transmission line leaving the plant, the generator owner should be responsible only for coordinating with the first set of line relaying encountered when proceding across the interconnecting element. He should not be responsible for coordinating with relaying at the opposite end of the interconnecting element. For example, in Figure 5 on Page 28 of the draft standard, Generator Owner T should not have to worry about a review of the relaying located at breakers G, F, or E. Another example is Figure 2, Page 25 of the draft standard: Generator Owner R should not be responsible for reviewing the relaying at the breaker C.

We believe that the proposed standard is too prescriptive regarding the specific duties and multiple time frames of each of the parties TO, DP, and GO. Including time frames for each Interconnect Element with regard to effective dates (6 mo), initial studies (48 mo.), studies triggered by change of equipment or change of fault current (6 mo.), TO/GO/DP agreed upon schedules (variable), delivery of studies (90 days), short circuit studies (24 mo.), notification to others of fault current changes (30 days), change detail notification (30 days), and review of summary results (90 days) is unnecessary and unduly burdensome. The process flow chart provided on page 22 of the draft standard is evidence of the complexity of the proposition. Please seriously consider the following simplified three-requirement approach which will similarly accomplish the desired outcome of coordination of the Protection System for Interconnected Elements.

R1) Require the two parties of the Interconnecting Element to jointly develop a Protection System Study - initially with X months to complete.

R2) Require a review / update of the protection system study for proper coordination anytime a change to the system may upset the coordination.

R3) Require a review / update of the protection system study for proper coordination every X years.

The measures for each requirement should simply be M1: has a protection system study been performed by the initial required date?; M2: has a protection system study been reviewed / updated for system changes which impact the coordination?; M3: has the protection system study been reviewed / updated every X years? During an audit period, these requirement and measures will drive entities to establish and maintain protection system studies. This approach keeps the focus on the protection system study rather than the multiple actions with varying time frame restrictions. We believe that these changes will results in an equally effective driver to establish coordination while keeping the standard as succinct as possible.

Consideration of Comments
Project 2007-06 System Protection Coordination

The System Protection Coordination Drafting Team thanks all commenters who submitted comments on draft 2 of PRC-027-1**.** The standard was posted for a 30-day public comment period from November 16, 2012 through December 17, 2012. Stakeholders were asked to provide feedback on the standard through a special electronic comment form. There were 82 sets of comments, including comments from approximately 220 different people from approximately 157 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received

Effective Dates

Based on discussion within the drafting team, the effective date was changed from "…the first day of the first calendar quarter that is six months beyond…" to "…the first day of the first calendar quarter that is 12 months beyond…" since there could be a significant number of Interconnected Elements requiring analysis due to the new requirements.

Definitions

Interconnected Element:

Based on comments related to the use of the term "Functional Entities" and the inclusion of the phrase "a Registered Entity that represents multiple functional entities", the drafting team revised the definition as follows:

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Interconnected Element: A BES Element that electrically joins facilities owned by:

a) separate Registered Entities, or

b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

Protection System Coordination Study

Based on the conflict of the abbreviation of a “Protection System Study” vs. a “Power System Study”, the drafting team revised the term to “Protection System Coordination Study”.

Purpose

Many commenters stated that the Purpose should not include the phrase “such that the least number of power system Elements are isolated to clear Faults” or had other suggestions to improve the Purpose. The drafting team changed the Purpose to: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.

Applicability:

PRC-027-1

To add clarity, the drafting team added the following sentence to the 4.2 Facilities: For the purpose of the requirements contained herein, the following Protection Systems owned by each Functional Entity in 4.1 above are those to which these requirements are applicable.

PRC-001-3

The Applicability section was updated to clarify which Protection Systems are applicable to Requirement R1. (The ‘Facilities’ portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)

Background

General updates to reflect recent activities associated with PRC-001 and the statuses of other ongoing projects.

Requirements

The time frame for Requirement R1, Part 1.1.1 was increased to 60 calendar months to allow entities with large numbers of Interconnected Elements enough time to complete the Protection System Coordination Studies.

The drafting team modified the timeframe in Requirement R1, Part 1.1.2 to "…12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2…" due to the fact that with the new requirements, the possibility exists there could be a significant number of Protection System Coordination Studies required.

The drafting team modified Requirement R1, Part 1.1.3 to add a six month timeframe for the notification related to Requirement R3, Part 3.3. It now reads: "According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or within six calendar months of being notified of a change as described in Requirement R3, Part 3.3; or technically justify why such a study is not required."

The drafting team modified Requirement R1, Part 1.2 for clarity.

Based on comments and drafting team discussions, Requirement R2 was revised to allow a technical justification demonstrating why Fault current does not affect the Protection System coordination, and the timeframe was revised from once every 24 months to once every 60 calendar months.

Based on comments, the equation in Requirement R2, Part 2.2 was restated - "% deviation" was replaced with "% change".

The drafting team modified Requirement R2, Part 2.2.1 for clarity.

The drafting team made minor edits to Requirement R3, Part 3.1 to provide clarity.

To clarify what was expected as a response, the drafting team modified Requirement R4, Part 4.1 as follows: Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Coordination Study (per Requirement R1, Part 1.2) and respond to the other owner(s): Accepting the results, or Rejecting the results, and suggesting modifications to resolve any identified coordination issues.

To clarify what was expected by the phrase 'confirming acceptance' used in the previous draft, the drafting team changed Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues. The drafting team explained in the responses that "accepting results" only indicates that the entity has not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agree with the other entities philosophy.

Measures:
PRC-027-1

A new Measure M3 was added to account for the option of providing a technical justification for not performing a short circuit study. The other measures were renumbered and/or modified to be consistent with the revised requirements.

PRC-001-3

A new Measure M1 was added. The Measure reads as follows: For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel.

Evidence Retention

The drafting team modified the language for consistency.

VSLs

The drafting team modified the VSLs for clarity and consistency with the revised requirements.

Guidelines and Technical Basis

Complementary changes were made to the Guidelines and Technical Basis corresponding to all changes to the standard.

The drafting team updated the process flow chart to align with the revised requirements, as well as updated the Example Process.

In the introductory section for the Diagrams, the drafting team revised the language and added notes to provide clarity.

The Figures were modified to identify the Interconnected Elements, and slightly modified Figure 5 for clarity.

The drafting team revised the description relating to Figure 3 in the “Guidelines and Technical Basis” to clarify that only the Distribution Provider’s Protection Systems installed for the purpose of detecting Faults on BES Elements are a part of the Applicability of this standard.

Unresolved Minority Views
PRC-027-1

- A few commenters disagreed with the 10% deviation trigger. The drafting team recognizes there are variations of margins used throughout the industry; however, believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.

- Several commenters expressed a desire to see the standard drafting team develop and include a conflict resolution process for situations where mutual agreement cannot be reached. The drafting team responded with the following: The drafting team believes that any conflict resolution should be handled through normal business practices.

- A couple of comments indicated that Transmission Owners could not share knowledge of its system with Generator Owners and, as such, Generator Owners should not be included in the Applicability. The drafting team disagreed that Transmission information could not be shared with Generator Owners and that there is a reliability benefit in requiring each entity to ensure proper coordination exists.

- A few commenters requested that the initial study in Requirements R1 part 1.1.1 be moved to the implementation plan. The drafting team investigated this as an option but did not make this change. The drafting team stated that it believes the current structure of Requirement R1, Part 1.1.1., as currently written, achieves this same goal.

- A few commenters believed Requirement R4, Part 4.2 was unnecessary and should be eliminated. The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.

PRC-001-3

- Several commenters asked about revisions to PRC-001. The drafting team noted several things related to this:

    - The drafting team did not modify the purpose.

    - The Applicability section was updated to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)

    - The drafting team did add Measure M1, which reads: "For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel."

    - The drafting team recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.

Index to Questions, Comments, and Responses

1. Based on stakeholder comments, the drafting team modified the Purpose of this standard to "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults." Do you agree with his Purpose? If not, please provide specific suggestions for change in the comment area. 20
2. The drafting team is proposing two definitions for use only with PRC-027-1 as follows: Interconnected Element: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity Protection System Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults. Do you agree with these definitions, if not please provide specific suggestions for change in the comment area. 44
3. In Requirement R1, the drafting team modified the time frame to allow entities 48 months to have a documented Protection System Study completed for each Interconnected Element if no Protection System Study exists. Note, the drafting team has allowed inclusion of all previously performed Protection System Studies whose summary of results include, at a minimum, the protective relay settings reviewed, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area. 67
4. In Requirement R4, the drafting team replaced the need to 'reach agreement' with 'confirming acceptance.' Do you agree with this change? If not, please provide specific suggestions for change in the comment area. 68
5. The requirements and associated measures were modified to indicate that information was 'provided' instead of 'demonstrating that each affected entity received notification.' Do you agree with this change? If not, please provide specific suggestions for change in the comment area... 116

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	1
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
9.	Donald Weaver	New Brunswick System Operator	NPCC, NPCC	2
10.	David Kiguel	Hydro One Networks Inc.	NPCC, NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC, NPCC	5
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC, NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC, NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC, NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC, NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC, NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC, NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC, NPCC	5
19.	Brian Robinson	Utility Services	NPCC, NPCC	8
20.	Ben Wu	Orange and Rockland Utilities	NPCC, NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC, NPCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light Co.	RFC	1, 3
2.	Alvin Depew	Pepco Holdings Inc	RFC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Steve Alexanderson P.E.	Western Small Entity Comment Group			X	X					X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Russ Schneider	Flathead Electric	WECC	3, 4
2.	Russell A. Noble	Cowlitz County PUD No. 1	WECC	3, 4, 5
3.	Rick Paschall	Blachly-Lane Electric Cooperative	WECC	3
4.	Rick Paschall	Central Electric Cooperative	WECC	3
5.	Rick Paschall	Consumers Power	WECC	1, 3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
6.	Rick Paschall	Clearwater Power Company	WECC	3
7.	Rick Paschall	Douglas Electric Cooperative	WECC	3
8.	Rick Paschall	Fall River Rural Electric Cooperative	WECC	3
9.	Rick Paschall	Northern Lights	WECC	3
10.	Rick Paschall	Lane Electric Cooperative	WECC	3
11.	Rick Paschall	Lincoln Electric Cooperative	WECC	3
12.	Rick Paschall	Raft River Rural Electric Cooperative	WECC	3
13.	Rick Paschall	Lost River Electric Cooperative Lost River Electric Cooperative	WECC	3
14.	Rick Paschall	Salmon River Electric Cooperative	WECC	3
15.	Rick Paschall	Umatilla Electric Cooperative	WECC	1, 3
16.	Rick Paschall	Coos-Curry Electric Cooperative	WECC	3
17.	Rick Paschall	West Oregon Electric Cooperative 4	WECC	3
18.	Rick Paschall	Pacific Northwest Generating Cooperative	WECC	3, 4, 8
19.	Rick Paschall	Power Resources Cooperative	WECC	6

				1	2	3	4	5	6	7	8	9	10
4.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jose Landeros	IID	WECC	1, 3, 4, 5, 6

				1	2	3	4	5	6	7	8	9	10
5.	Group	Joseph DePoorter	Midwest Reliability Organization NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Tom Breene	WPS	MRO	3, 4, 5, 6
4.	Jodi Jenson	WAPA	MRO	1, 6
5.	Ken Goldsmith	ALTW	MRO	4
6.	Alice Ireland	XCEL (NSP)	MRO	1, 3, 5, 6
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Kayleigh Wilkerson	LES	MRO	1, 3, 5, 6
9.	Joseph DePoorter	MGE	MRO	3, 4, 5, 6
10.	Scott Nickels	RPU	MRO	4

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11. Terry Harbour	MEC	MRO	1, 3, 6
12. Marie Knox	MISO	MRO	2
13. Lee Kittelson	OTP	MRO	1, 3, 5, 6
14. Scott Bos	MPW	MRO	1, 3, 5, 6
15. Tony Eddleman	NPPD	MRO	1, 3, 5
16. Mike Brytowski	GRE	MRO	1, 3, 5, 6
17. Dan Inman	MPC	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jonathan Hayes	Southwest Power Pool	SPP	NA
2. Robert Rhodes	Southwest Power Pool	SPP	NA
3. Greg Froehling	Rayburn Electric		NA
4. Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
5. Valerie Pinnamonti	American Electric Power	SPP	1, 3, 5
6. Clem Cassmeyer	Western Farmers	SPP	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Michael Jones	National Grid and Niagara Mohawk (A National Grid Company)	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Michael Schiavone	Niagara Mohawk (A National Grid Company)	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Dean Bender	SPC Technical Svcs	WECC	1
2. Deanna Phillips	FERC Compliance	WECC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Mary Jo Cooper	GP Strategies	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Elizabeth Kirkley	City of Lodi	WECC	3
2. Colin Murphey	City of Ukiah	WECC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
3.	Douglas Draeger	Alameda Municipal Power	WECC	3
4.	Angela Kimmey	Pasadena Water and Power	WECC	1, 3
5.	Blaine Ladd	California Pacific Electric Company	WECC	3
6.	Ken Dize	Salmon River Electric Co-op	WECC	3
7.	Michael Knott	Granite State Electric	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rick Terrill	Luminant Generation Company LLC	ERCOT	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Edwards	Electric Transmission	SERC	1, 3
2.	Sean Iseminger	Fossil & Hydro	SERC	5
3.	Chip Humphrey	Fossil & Hydro	NPCC	5
4.	Connie Lowe	NERC Compliance Policy	RFC	5, 6
5.	Jeff Bailey	Nuclear	NPCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	David Greene	SERC Protection and Controls Subcommittee (PCS										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bridget Coffman	Santee Cooper	SERC	
2.	Steve Edwards	Dominion, Virginia Power	SERC	
3.	Ernesto Paon	MEAG Power	SERC	
4.	Greg Davis	Georgia Transmission	SERC	
5.	James Evans	SCANA	SERC	
6.	Paul Nauert	Ameren	SERC	
7.	George Pitts	TVA	SERC	
8.	David Greene	SERC	SERC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Ben Engelby	ACES Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

1.	John Shaver	Arizona Electric Power Cooperative Inc. and Southwest Transmission Cooperative Inc.	WECC	1, 4, 5
2.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
3.	William Hutchison	Southern Illinois Power Cooperative	SERC	1
4.	Chris Bradley	Big Rivers Electric Corporation	SERC	
5.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
6.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
7.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
8.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
9.	Amber Anderson	East Kentucky Power Cooperative	SERC	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
14.	Group	Sasa Maljukan	Hydro One Networks Inc.	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Difilippo	Hydro One Networks Inc.	NPCC	1
2.	David Kiguel	Hydro One Networks Inc.	NPCC	1

				1	2	3	4	5	6	7	8	9	10
15.	Group	paul haase	seattle city light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	make haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

				1	2	3	4	5	6	7	8	9	10
16.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Service	FRCC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Group	Charles Yeung	Certain Members of the ISO RTO Council		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Campoli	NYISO	NPCC	2
2.	Ali Miremadi	CAISO	WECC	2
3.	Bill Phillips	MISO	RFC	2
4.	Steve Myers	ERCOT	ERCOT	2
5.	Ben Li	IESO	NPCC	2

				1	2	3	4	5	6	7	8	9	10
18.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Detweiler	FirstEnergy	RFC	1, 3, 4
2.	Bill Duge	FirstEnergy	RFC	5
3.	Robert Loy	FirstEnergy	RFC	5
4.	Brian Orians	FirstEnergy	RFC	5
5.	Larry Raczkowski	FirstEnergy	RFC	1, 3, 4, 5, 6

				1	2	3	4	5	6	7	8	9	10
19.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6
5.	Daniel McNeely		SERC	1

				1	2	3	4	5	6	7	8	9	10
20.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
4.			WECC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

5.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6
6.			NPCC	6
7.			SERC	6
8.			SPP	6
9.			RFC	6
10.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
22.	Group	Thomas McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
23.	Individual	Joe Uchiyama	US Bureau of Reclamation	X				X				X	
24.	Individual	Rowell Crisostomo	ATCO Electric	X									
25.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
26.	Individual	Janet Smith	Arizona Public Service Company	X		X	X	X	X	X			
27.	Individual	Ed Croft	Operational Compliance	X		X		X					
28.	Individual	ryan millard	pacificorp	X		X	X	X					
29.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
30.	Individual	Antonio Grayson	Southern Company	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
31.	Individual	Jim Watson	Dynegy					X					
32.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
33.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP					X					
34.	Individual	Andrew Z. Pusztai	American Transmssion Company, LLC	X									
35.	Individual	Si Truc PHAn	Hydro-Quebec TransEnergie	X									
36.	Individual	NICOLE BUCKMAN	ATLANTIC CITY ELECTRIC COMPANY			X							
37.	Individual	Don Jones	Texas Reliablity Entity										X
38.	Individual	Patrick Brown	Essential Power, LLC					X					
39.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
40.	Individual	Mark Yerger	Potomac Electric Power Compan			X							
41.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
42.	Individual	Scott Miller	MEAG Power	X									
43.	Individual	Wryan Feil	Northeast Utilities	X		X		X					
44.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
45.	Individual	Thad Ness	American Electric Power	X		X		X	X				
46.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
47.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
48.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
49.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
50.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
51.	Individual	David Jendras	Ameren	X		X		X	X				
52.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
53.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
54.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									
55.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
56.	Individual	Jim Howard	Lakeland Electric	X		X		X	X				
57.	Individual	Larry Watt	Lakeland Electric	X		X		X	X				
58.	Individual	Michael Moltane	ITC	X									
59.	Individual	Michael Falvo	Independent Electricity System Operator		X								
60.	Individual	Anthony Jablonski	ReliabilityFirst										X
61.	Individual	Jonathan Meyer	Idaho Power Co.	X									
62.	Individual	Brian Murphy	NextEra Energy	X		X		X	X				
63.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
64.	Individual	Saul Rojas	New York Power Authority	X		X		X	X			X	
65.	Individual	Stephanie Monzon	PJM Interconnection		X								
66.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
67.	Individual	Richard Vine	California Independent System Operator	X	X	X	X	X	X				
68.	Individual	John Bee	Exelon Corporation and its affiliates										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
69.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
70.	Individual	Mike Hirst	Cogentrix Energy Power Management, LLC					X					
71.	Individual	Marie Knox	MISO		X								
72.	Individual	Jim Cyrulewski	JDRJC Associates								X		
73.	Individual	Clay Young	SCE&G	X		X		X	X				
74.	Individual	Daniela Hammons	CenterPoint Energy	X									
75.	Individual	Greg Davis	Georgia Transmission Corporation	X									
76.	Individual	Scott McGough	Georgia System Operations Corporaton			X							
77.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
78.	Individual	Angela P Gaines	Portland General Electric Co	X		X		X	X				
79.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
80.	Individual	Karen Webb	City of Tallahassee	X		X		X					
81.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
82.	Individual	Rich Salgo	NV Energy	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Comments of "Entity Name"
Illinois Municipal Electric Agency	Florida Municipal Electric Agency
Hydro-Quebec TransEnergie	NPCC
ATLANTIC CITY ELECTRIC COMPANY	Pepco Holdings Inc and Affiliates
Delmarva Power & Light Company	Potomac Electric Power Company, Transmission Owner (Segment 1)
Potomac Electric Power Compan	Pepco Holdings Inc and Affiliate
MEAG Power	Essential Power, LLC
Northeast Utilities	Northeast Power Coordinating Council Inc. (NPCC)1040 Avenue of the Americas10th FloorNew York, NY 10018
Consolidated Edison Co. of NY, Inc.	NPCC, the Northeast Power Coordinating Council
Flathead Electric Cooperative, Inc.	Support both the previous comments of Bonneville Power Administration and the comments of the Western Small Entity Comment Group

Organization	Supporting Comments of "Entity Name"
Lincoln Electric System	MRO NSRF
The United Illuminating Company	Northeast Power Coordinating Council (NPCC)
Lakeland Electric	FMPA
Lakeland Electric	Please see FMPA comments.
New York Power Authority	NPCC
California Independent System Operator	The California ISO is in support of, and has signed on with, the comments submitted by the Standards Review Committee (SRC) (ISO/RTO Council).
MISO	MISO supports the comments submitted by the Standards Review Committee (SRC).
JDRJC Associates	Midwest ISO
Georgia System Operations Corporaton	Georgia Transmission Corporation
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing

1. **Based on stakeholder comments, the drafting team modified the Purpose of this standard to "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults." Do you agree with this Purpose? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Many commenters stated that the purpose should not include the phrase "such that the least number of power system Elements are isolated to clear Faults" or had other suggestions to improve the Purpose. The drafting team revised the Purpose to read: "To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults."

Some commenters stated that the definition of "Interconnected Element" needed to be changed. The drafting team changed the definition to:

A BES Element that electrically joins facilities owned by:

a) separate Registered Entities, or

b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

Some commenters noted that a Transmission Owner could not share knowledge of its system with Generator Owners, as such; Generator Owners should not be included in the Applicability. The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the Generator Owner to ensure the Protection Systems covered by this standard are properly coordinated.

Others commenters believed that the Generator Owner should be excluded because the Transmission Owner is the entity that maintains that Transmission System Fault studies. While the drafting team agrees that Transmission Owners usually maintain the Fault studies, it believes that both entities have a responsibility to ensure the Protection Systems covered by this standard are properly coordinated.

A commenter believed that the Purpose of PRC-001-3 should be changed. The drafting team did not modify the Purpose, but did add Measure M1. It reads: "For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel."

A few commenters requested more clarity on which Protection System are included in the standard. The drafting team explained that because of differing philosophies among entities, it could not specify all Protection Systems that may require coordination. The drafting team believes the Applicability section gives sufficient guidance.

A commenter indicated that "coordination" is not well-defined. Rather than trying to develop a definition in the NERC Glossary of Terms, the drafting team chose to express what was intended for "coordination" in this standard.

There was a concern that the standard might be expanding into Distribution Elements. The drafting team explained that the Applicability only applies to Distribution Providers that own "Protection Systems installed for the purpose of detecting Faults on BES Elements and that require coordination for isolating those Faulted Elements."

A commenter disagreed with the need to periodically review coordination. The drafting team indicated that it believes there is a reliability benefit in periodically reviewing Protection System coordination.

One comment indicated that the Figures needed more explanation regarding which were the "Interconnected Elements." The drafting team modified the figures to indicate the "Interconnected Elements."

One commenter stated that there was a lack of consistency between the Purpose and Requirement 1, Part 1.2. The drafting team revised the language of both to remove any inconsistencies.

Organization	Yes or No	Question 1 Comment
Nebraska Public Power District	No	It seems the real purpose of this standard is "To coordinate BES Protection Systems for Interconnected Elements". The rest of the statement is already covered as part of the protection systems design which will involve coordination or not depending on any special issues or existing design limits.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. The Purpose has been revised based on your and others' comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults		
ACES Standards Collaborators	No	(1) We disagree with the inclusion of the "least number of power system Elements" in the purpose. The purpose should be to simply coordinate the Protection Systems for Interconnected Elements. While trying to minimize the number of Elements that should be removed from service is a laudable goal, it will create an incentive for auditors to determine if there is a better way to protect the registered entities systems. How else could an auditor know that the absolute minimum of Elements have been determined unless they tried optimize the zone of protection themselves. The use of different but related terms causes confusion. For instance, what is the difference among "power system Elements," "Elements," and "Interconnected Elements"? Based on the definition of "Element," we assume "power system Elements" is intended to be the same. If so, we suggest dropping "power system" to avoid confusion. (2) Similar to the purpose statement, the Applicability Section, (4.2) Facilities is unclear. The statement "Interconnected Elements of the BES that require coordination for isolating those faulted Elements" includes superfluous language. In general, NERC enforces standards against the BES. Thus, it is not necessary to include "of the BES." To ensure absolute clarity, we suggest the definition of Interconnected Element be modified to specifically limit it to the BES as well. Also, we recommend striking everything after Interconnected Elements in the purpose statement as it is unnecessary and provides no additional clarification on the Facilities to which the standard applies. (3) Because no generic questions asking for additional comments was provided, we are providing our concerns that do not fall under one of the specific questions asked of the drafting team here. (4) Please change the wording of Part 1.2 as the current wording has some

Organization	Yes or No	Question 1 Comment
		unintended consequences. We think “to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement” should be changed to “to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of the associated Protection System Study.” The current language literally reads that the TO, GO, and DP shall provide the PSS results to itself. It also reads that all the Protection System Studies for a TO, GO, or DP must be provided to the other protection system owners of all of the Interconnected Elements even if the other owners only own protection systems for one of the TO, GO, or DP’s Interconnected Elements. As an example, consider that TO X shares two separate Interconnected Elements with TO Z and GO A. The Interconnected Element between TO X and TO Z is called Tie-line B and the Interconnected Element between TO X and GO A is GSU C. The requirement would literally require TO X to share its Protection System Study results for both Tie-line B and GSU C with both GO A and TO Z even though, GO A has no interest in Tie-Line B and TO Z has no interest in GSU C. This could be solved with the simple edit described above. (5) We find that addition of “For each Facility associated with an Interconnected Element on its System” in R2 confusing. First, what is an associated Facility? Second what is intended by the use of Facility instead of Element? Considering Interconnected Facility in the last draft was change to Interconnected Element and Facility was used in this requirement, it would appear some delineation is meaning is intended between Element and Facility. Since Element and Facility have nearly the same meaning in the NERC Glossary of Terms that delineation is unclear and we would appreciate further explanation of the intent. (6) We found the inclusion of quotes on the phrase “Protection Systems installed to detect faults on the BES Transmission System” confusing. There is no reference. We suggest removing the quotes as they are superfluous. The meaning is still communicated without them. If they remain, please provide a

Organization	Yes or No	Question 1 Comment
		reference. We assumed it came from section 4.2. If the quote did come from that section, it is not quite correct. It is missing “for the purpose of detecting” and “faults” is not capitalized (7) The purpose statement of PRC-001-3 needs to be further modified. With the deletion of all of the requirements but Requirement R1, the purpose to “ensure system protection is coordinated among operating entities” is no longer achieved.

Response: Thank you for your comments.

1. **The Purpose has been revised based on your and others’ comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.**
2. **The definition of Interconnected Element has been revised based on your and others’ comments to read:**
   A BES Element that electrically joins facilities owned by:
   a) separate Registered Entities, or
   b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).
3. **NA**
4. **The suggested change has been made**
5. **The language in Requirement R2 has been clarified**
6. **The phrase you mentioned has been modified to accurately reflect the language in the Figure from which it was taken.**
7. **The large majority of the Standard is a carryover from the standards PRC-001-1 and PRC-001-2. As noted in the background section of PRC-027-1, the drafting team is recommending that Requirement R1 only remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. At that time PRC-001-3 will be retired.**

Organization	Yes or No	Question 1 Comment
Certain Members of the ISO RTO Council	No	Although the SRC agrees that protection systems should strive to interrupt only those elements closest in to a fault to avoid excessive interruptions, there are situations where it is necessary to trip elements beyond those that only interrupt the fault. To set a result for “...the least number of power system Elements are isolated to clear Faults” misses the primary goal for a reliability

Organization	Yes or No	Question 1 Comment
		standard meant to protect the interconnected bulk electric grid. NERC standards should always have the underlying purpose to prevent cascading failures that affect interconnected systems. The stated Purpose must recognize that the "least number of power system Elements are isolated to clear Faults to maintain system integrity". For example, a relay scheme could isolate a fault on a generator connected between two line terminals by opening the breakers on both ends of the line. This would fulfill the Purpose of "least number of power system Elements", however, a protections scheme for that segment of transmission line may require that the next terminal along that line also be interrupted in order to prevent an unintended increase in load to a particular element due to the opening of the breakers closest to the fault.
Response: Thank you for your comment. The Purpose has been revised based on your and others' comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
Northeast Power Coordinating Council	No	1. By restricting the coverage to "... Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults" there is a significant gap in reliability created by the exclusion of elements such as loss of field, out-of-step, etc. 2. An incomplete Protection System Study negates all the work needed to satisfy this Standard. Perhaps through referencing the NERC technical reference document entitled "Power Plant and Transmission Protection Coordination", there could be a reference to which protection elements are going to be covered in this Standard and likewise what Standards will cover the protection elements not covered by this Standard. 3. As identified by the Drafting Team, there may be no evidence of mis-coordination between traditional protections that detect faults, but for co-ordination of generator loss of excitation protection settings or out of step relaying during a fault condition - is that meant to be covered in this Standard

Organization	Yes or No	Question 1 Comment
		or elsewhere? 4. The latest draft of PRC-019-1 indicates studies conducted under that standard are for steady state conditions, not fault conditions. PRC-023 provided clear direction on what protection elements to mitigate and even provided options on how to mitigate those elements. PRC-027 should provide the similar effective vehicle to convey at least the "what" for Protection System coordination during faults between entities, and will allow entities to perform and document consistent Protection System Studies. 5. The term "coordination" is not well defined. Does it mean ensuring owners of all terminals of a line, transformer, etc. are aware of each other's protection system design and settings, especially when the design, settings, and physical system changes? Developing a formal definition to be included in the NERC Glossary should be considered.
Response: Thank you for your comments. 1. **The coordination of non-fault-related Protection Systems such as what you describe is not within the scope of this standard.** 2. **Because there are different Protection System designs and philosophies, the drafting team cannot specify which Protection Systems require coordination.** 3. **The drafting team believes that conditions such as those that you suggested are expected to be remedied under other standards. For example, out-of-step conditions should be identified and mitigation coordinated and implemented as a result of a transmission system assessment required in the TPL standards.** 4. **The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System components need to be coordinated between entities.** 5. **The drafting team agrees that "coordination" is not well-defined. Rather than trying to develop a definition in the NERC Glossary of Terms, the drafting team chose to express what was intended for coordination in this standard.**		
CenterPoint Energy	No	CenterPoint Energy believes the purpose should use wording similar to that being proposed for the definition of "Protection System Study" instead of developing and utilizing different wording for the purpose statement.

Organization	Yes or No	Question 1 Comment
		CenterPoint Energy recommends the purpose be stated as follows: "To coordinate Protection Systems for Interconnected Elements, such that Protection Systems operate as desired for clearing postulated short circuit Fault events."
Response: Thank you for your comment. The Purpose has been revised read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
NV Energy	No	Concerned that the Applicability and Purpose are encroaching upon Distribution elements, outside the statutory authority of the NERC Standards process
Response: Thank you for your comment. Per the Applicability, the standard applies only to Distribution Providers that own "Protection Systems installed for the purpose of detecting Faults on BES Elements and that require coordination for isolating those faulted Elements." This standard does not pertain to distribution (non-BES) Elements.		
Exelon Corporation and its affiliates	No	Exelon agrees with the Purpose statement as stated, however the questions and layout of this comment form doesn't provide an area to provide comments as to why we are voting negative. While requiring periodic coordination studies between entities is laudable, it is unnecessary. The coordination of a protection system, by nature, is tested every time it operates. We already have a standard, PRC-004-2, that requires all transmission protection system operations to be analyzed for correctness and any misoperations reported, along with corrective action plans to mitigate their cause. Our experience indicates the bulk of protection system misoperations are not caused by a lack of coordination studies. This standard, as written, continues to be vague and will lead to an inconsistent application of the requirements. Most importantly, we believe this standard is ill advised. Coordination of protection systems between entities was not a factor in the 2003 blackout. As such it clearly goes beyond the mandate of the 2003 blackout recommendations. Implementation of this standard will add little to the reliability of the bulk electric system while adding substantially to the amount of time and money an entity spends simply on compliance

Organization	Yes or No	Question 1 Comment
		activities. Contrary to the goal of enhancing reliability, this standard will simply dilute available resources to the detriment of reliability.
Response: Thank you for your comment. The drafting team believes there is a reliability benefit to review and ensure proper Protection System coordination on existing Protection Systems associated with Interconnected Elements prior to potentially being identified by a misoperation. The aspects of coordination included in the existing Reliability Standard PRC-001-2 are incorporated and clarified in the proposed Reliability Standard PRC-027-1.		
FirstEnergy	No	In regard to the purpose statement, FirstEnergy supports the response submitted by the RFC Protection Subcommittee which is repeated here for convenience. The purpose should mirror the objectives of the Protection Systems Study. “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence.” The reasons being that an entity may choose to overtrip distribution transformer (non-BES) protection, to employ zone 1 extension schemes, or for other valid reasons trip more than the least number of Elements to clear a Fault.
Response: Thank you for your comment. The Purpose has been revised based on your and others’ comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
Pepco Holdings Inc & Affiliates	No	The language in the Statement of Purpose needs to be reworded. The phrase “such that the least number of power system Elements are isolated to clear faults” may restrict certain protection practices in widespread use today, where coordination on tapped distribution facilities is achieved via auto-reclosing rather than via coordinated time delays. For example, a BES line (protected by a high speed DCB or POTT pilot scheme) is tapped by a distribution provider as demonstrated in Figure 3 of the Application Guidelines. Very often for distribution taps like these, rather than requiring the distribution provider to establish a costly transmission class pilot scheme terminal at breaker C with communication links to A & B, it is common to let the pilot scheme reach into

Organization	Yes or No	Question 1 Comment
		(but not thru) the transformer at C. For faults in the transformer the high speed transformer relays will operate to trip and lockout breaker C. However, the pilot scheme at A & B will also trip simultaneously. Breaker C will lockout and A & B will auto-reclose to restore the line. Coordination is achieved via auto-reclosing. For faults on the line, A & B will trip via the pilot scheme, and if generation happens to be running either C will trip, or the generator will trip depending on scheme design. Reclosing at A & B would be delayed and / or voltage supervised to ensure generation has been removed prior to auto-reclosing. In the above scenarios since the line tripped for a fault in the transformer, or the generator tripped for a fault on the line, it would violate the requirement that “the least number of power system Elements are isolated to clear faults”. The language used in the proposed definition of Protection System Study is better; using the phrase “demonstrates ... Protection Systems operate in the desired sequence for clearing faults”. The problem here is who determines what is the “desired sequence”? Would a scheme, which is purposely designed as described above and acknowledged by the Transmission Planner and Transmission Operator, be considered to operate in the “desired sequence” for clearing faults? The language in the standard needs to be re-visited to enable these types of protection interfaces with distribution providers having limited generation resources connected downstream. Also, if system reliability was truly an issue for this example, the interconnection should not have been a simple tap on the line, but rather a ring bus should have been established at the interconnection point. In conclusion, we suggest re-wording the Purpose to read: “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence for clearing Faults.” This statement is consistent with the stated definition of the Protection System Study, on which the measures of this standard are based.

Response: Thank you for your comment. The Purpose has been revised based on your and others’ comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired

Organization	Yes or No	Question 1 Comment
sequence during Faults.		
Florida Municipal Power Agency	No	The primary purpose of protection system coordination is to ensure faults are cleared expeditiously and well under the critical clearing time, with the stated purpose of minimizing the number of elements isolated as a secondary consideration, not a primary consideration. As such, there is no recognition of the importance of remote back-up protection that backs up primary and secondary protection, but, does not necessarily share the same goal of minimizing number of elements tripped, but, does share the goal of clearing a fault within the critical clearing time.
Response: Thank you for your comment. The drafting team agrees with your statement that critical clearing time is important. The drafting team revised the Purpose: however, the team believes that minimizing the elements isolated is simply a part of accomplishing that clearing time. The coordination between the primary and backup protection that you address has to take place, otherwise there would always be isolation of more than is necessary to clear the Faults.		
Bonneville Power Administration	No	The Purpose given assumes that the most important outcome of a protection system operation is that the least number of power system elements are isolated to clear a fault. While it is true that it is usually desirable to prevent parallel paths from opening, in many cases it might be perfectly acceptable for adjacent elements to operate. BPA believes it may be more economical to have a protection system that isolates elements in addition to the faulted element if the isolation of the additional elements does not result in problems for the BES. A suggested Purpose statement that takes this philosophy into account is: To insure that separate Functional Entities properly coordinate with each other the protective systems for elements that interconnect their electrical systems so that only the intended power system elements will be isolated to clear a fault.
Response: Thank you for your comment. The Purpose has been revised read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		

Organization	Yes or No	Question 1 Comment
Essential Power, LLC	No	The purpose is laudable, but the means by which it is to be achieved needs more work. The Application Guidelines section of PRC-027 makes reference to, “the entity performing the Protection System Study [for R1],” but the standard provides no indication of who this should be. This responsibility is simply assigned to, “Each Transmission Owner, Generation Owner, and Distribution provider.” The obligation placed on GOs by use of the word “each” in R1 cannot be fulfilled, however, except under the circumstance of having a vertically-integrated utility. An independent GO does not have knowledge of the TO’s system, and in a deregulated market is not allowed to have such knowledge. The TO and TOP are provided with detailed information of the GO’s equipment, however, and therefore perform all interconnection-related studies. This is as it should be, because changes in the transission don’t matter to a GO. We do not modify our Protection Systems in response to changes to the Fault current at an interconnecting bus, we just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Everything involving sequencing the tripping of multiple Elements is in the TO’s system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e. reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should say so, rather than pulling in all GOs regardless of whether or not it makes any sense for them to be involved. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performend by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.
Response: Thank you for your comment. The drafting team does not believe that the Transmission Owner is restricted in providing		

Organization	Yes or No	Question 1 Comment
the Protection System data necessary for the Generator Owner to ensure the Protection Systems covered by this standard are properly coordinated.		
Cogentrix Energy Power Management, LLC	No	The purpose is laudable, but the means by which it is to be achieved needs more work. The Application Guidelines section of PRC-027 makes reference to, "the entity performing the Protection System Study [for R1]," but the standard provides no indication of who this should be. This responsibility is simply assigned to, "Each Transmission Owner, Generation Owner, and Distribution provider." The obligation placed on GOs by use of the word "each" in R1 cannot be fulfilled, however, except under the circumstance of having a vertically-integrated utility. An independent GO does not have knowledge of the TO's system, and in a deregulated market is not allowed to have such knowledge. The TO and TOP are provided with detailed information of the GO's equipment, however, and therefore perform all interconnection-related studies. This is as it should be, because changes in the transission don't matter to a GO. We do not modify our Protection Systems in response to changes to the Fault current at an interconnecting bus, we just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Everything involving sequencing the tripping of multiple Elements is in the TO's system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e. reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should address that specifically. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performend by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">Response: Response: Thank you for your comment. The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the Generator Owner to ensure the Protection Systems covered by this standard are properly coordinated.</td></tr>
<tr><td>PPL Corporation NERC Registered Affiliates</td><td>No</td><td>1. The purpose of this study should be “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the proper sequence.” The least number of Elements to clear a Fault may not always be the case for some Protection Systems.
2. The TO and TOP are provided with detailed information of the GO’s equipment and therefore perform all interconnection-related studies. Independent generators do not modify Protection Systems in response to changes to the Fault current at an interconnecting bus, generators just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Equipment involving sequencing the tripping of multiple Elements is in the TO’s system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e., reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should specifically address those GOs, rather than pulling in all GOs. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performed by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The Purpose has been revised to read: To coordinate Protection Systems for Interconnected Elements, such that Protection</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
System components operate in the desired sequence during Faults. **2. The drafting team believes that although the Transmission Owner may provide the majority of the data and work associated with this standard, the Generator Owner shares the responsibility of ensuring the Protection Systems covered by this standard are properly coordinated.**		
Wisconsin Electric Power Company	No	The purpose should mirror the objectives of the Protection System Study: "To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence." There are cases where industry practice is to "overtrip", for example, for a tapped non-BES distribution transformer fault by tripping BES line breakers and reclosing. Also it may be a common practice to use zone 1 extension or acceleration schemes. There can be good reasons for intentionally tripping more than "the least number of Elements to clear a Fault". The Purpose statement as currently written is in conflict with these valid industry practices, and needs to be modified.
Response: Thank you for your comment. The Purpose has been revised based on your and others' comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
Kansas City Power & Light	No	1. The reliability objective of this standard should be to insure that there is an agreement between two interconnected entities of relay protection schemes and relay protection settings for the interconnected facilities. This is achieved if there is documentation stating that the Interconnected operating companies have reached agreement on protection schemes and protective relay settings. This standard should only require documentation that neighboring owners are talking and agreeing with one another in relation to protection and control. 2. The purpose in the draft standard makes it appear that you are in violation of this standard any time the system has a misoperation because of relay setting regardless of whether both parties have agreed on the settings used, but the measures tend to measure agreement with

Organization	Yes or No	Question 1 Comment
		the other entity. PRC-004 is the standard for misoperation reporting and misoperation mitigation.
Response: Thank you for your comment. 1. **The drafting team does not see a conflict between the language in the standard and your statement "This standard only requires documentation that neighboring owners are talking and agreeing with one another in relation to protection and control." The measures provide examples of documentation that demonstrate compliance with the requirements.** 2. **A Misoperation is not a violation of PRC-027-1.**		
US Bureau of Reclamation	Yes	1) We agree to isolate the least number of power system elments during a fault. However, PRC-027 & PRC-001 are lack of a statement which elements be reviewed by entities. It seems like it is upto utilities to decide wchich elements to be reviewed and studied for. For the comliance purpose, how does Autority judge the reviews/documents were meeting PRC-027? 2) Pg. 2- Definitions of Terms Used in Standard- "Interconnected Element: An Element that electrically joins separate Functional Entities, includingthose Functional Entities that are a part of the same Registered Entity." -The Interconnected Element definition should be expanded upon and attached figures added showing what is and is not an interconnected element relative to the generator and generation owner. 3) Page 2 - The term "Functional Entities" as used in the definitions for "Interconnected Element" should include a definition. 4) Pg. 4- A.5 -"Other Aspects of coordination of Protection Systems addressed by other Projects: Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects." -The paragraph should be more specific as to whether the "fault clearing" referenced is used for primary

Organization	Yes or No	Question 1 Comment
		transmission line protection or primary generator/generator step-up transformer protection. Namely, does what is addressed in PRC-027-1 exclude fault clearing used for primary generator/generator step-up transformer protection? 5) Pg. 8- R3.- 3.1- " o New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios."- The sentence should be changed to read- " o New installation, replacement with different types, or modification of: fault clearing protective relays or protective function settings, related communication systems, related current transformer ratios and voltage transformer ratios." 6) Last paragraph on page 26 starting with "Protection Systems installed to detect faults on the BES..." has some great examples (especially the last sentence of that paragraph) of the intent of PRC-027. I think it would be useful to move or copy this type of verbiage to the beginning of the document and use it in the definitions to accomplish what Pete has commented on below.

Response: Thank you for your comments

1. **The drafting team believes that the "elements be reviewed by entities" are clearly identified in the definitions and Applicability sections.**
2. **The figures have been modified to indicate the "Interconnected Element'.**
3. **The definition of Interconnected Element has been changed to: A BES Element that electrically joins facilities owned by:**
   a) separate Registered Entities, or
   b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).
4. **This standard does include those aspects of "primary generator/generator step-up transformer protection" which may require coordination with other owners. An example would be back-up distance protection or ground overcurrent protection.**
5. **The drafting team believes the definition of Protection Systems (NERC Glossary of Terms) provides adequate clarity with regards to these components. The drafting team therefore declines to incorporate your suggested changes.**

Organization	Yes or No	Question 1 Comment
6. The drafting team declines to make the suggested change.		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with question 1, we have the following general comment: The purpose statement and R1.2 refers to Elements within the 'power system' which is not defined, while the 'Facilities' refers to 'Elements of the BES' and the 'Requirements' reference Interconnected Element on a particular entities' 'System' or 'transmission system'. Should these be consistent or has this been done purposefully?
Response: Thank you for your comments. The drafting team modified the language to make it consistent.		
SERC Protection and Controls Subcommittee (PCS	Yes	Based on the SDT response to our Draft 1 comment regarding the use of 'coordination', we understand 'coordination' in the Title and Purpose to mean the technical aspect of relay coordination.
Response: Thank you for your comments. The drafting team agrees with your statement.		
Georgia Transmission Corporation	Yes	Based on the SDT response to our Draft 1 comment regarding the use of 'coordination', we understand 'coordination' in the Title and Purpose to mean the technical aspect of relay coordination.
Response: Thank you for your comments. The drafting team agrees with your statement.		
Dominion	Yes	1). Dominion appreciates the SDT's agreement that in PRC 001 there were different interpretations of the term "coordination. Based on the SDT response to our Draft 1 comment regarding "coordination", we now understand that 'coordination' in PRC 027 Title and Purpose is referring to the technical aspects of coordinating relay settings. 2). Please reconsider Dominion previous recommendations to change the Title. "Protection System Interconnected Element Coordination for Performance

Organization	Yes or No	Question 1 Comment
		During Faults" or "Protection System Coordination for Interconnected Elements" have more specificity and meaning to the standards intent for coordinating relays on interconnections.
Response: Thank you for your comments. **1. The drafting team agrees with your statement.** **2. The drafting team declines to make the suggested change.**		
American Transmssion Company, LLC	Yes	However, ATC recommends that the Purpose statement in the Standard be modified by adding the word "intended" :"To coordinate Protection Systems for Interconnected Elements, such that the least number of intended power system Elements are isolated to clear Faults."
Response: The Purpose has been revised based on your and others' comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration agrees that it is appropriate that PRC-027-1 is self-contained throughout. Even though the Purpose statement is not necessarily mandatory and effective, it is conceivable that the previous version would lead a Compliance Enforcement Authority to require evidence that fault studies account for relay performance governed by other NERC standards. This could result in the assessment of two penalties for the same violation - a double jeopardy condition that should be avoided.
Response: Thank you for your support. The Purpose has been revised to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
Duke Energy	Yes	The Purpose statement could be improved by striking the phrase "least number of power system Elements are isolated to clear Faults", and inserting the following phrase from the definition of Protection System Study: "Protection Systems operate in the desired sequence for clearing Faults". Some entities

Organization	Yes or No	Question 1 Comment
		may choose to "over-trip" for certain Faults.
Response: Thank you for your comment. The Purpose has been revised based on your and others' comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
Independent Electricity System Operator	Yes	We agree with the purpose statement, but suggest to add "settings" after protection system (with the "s" removed") to make it clear that it is the coordination of the settings, not the design of protection systems.
Response: Thank you for your comment. The drafting team believes that 'settings' are not the only aspect of Protection Systems that can impact the stated purpose.		
Hydro One Networks Inc.	Yes	We agree with this Purpose statement and we commend the drafting team for moving this standard in the right direction. 1. However, in line with our previous comments from the first posting, there still seems to be a significant gap in reliability by not identifying what elements of the Protection System need to be co-ordinated between entities. Perhaps this can even reside in the Application Guide. 2. A poor or incomplete Protection System Study is worthless and negates all the work needed to satisfy this standard. 3. As identified by the drafting team, there may be no evidence of mis-coordination between traditional protections that detect faults, but for co-ordination of say generator loss of excitation protection settings or out of step relaying during a fault condition - is that meant to be covered in this standard or elsewhere? 4. The latest draft of PRC-019-1 indicates studies conducted under that standard are for steady state conditions - not fault conditions. PRC-023 provided clear direction on what protection elements to mitigate and even

Organization	Yes or No	Question 1 Comment
		provided options on how to mitigate those elements. We feel PRC-027 is an effective vehicle to convey at least the "what" for Protection System co-ordination during faults between entities and will allow entities to perform and document consistent Protection System Studies.
Response: Thank you for your comments and support. **1. Because there are different Protection System designs and philosophies, the drafting team cannot specify which Protection Systems require coordination.** **2. The drafting team agrees with your comment.** **3. The drafting team believes that conditions such as those that you suggested are expected to be remedied under other standards. For example, out-of-step conditions should be identified and mitigation coordinated and implemented as a result of a transmission system assessment required in the TPL standards.** **4. The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System components need to be coordinated between entities.**		
Ameren	Yes	We are voting negative for three reasons, one provided below and two are included in response to Question #3. Ameren also supports the SERC Protection & Control Subcommittee (PCS) comments and hereby includes them by reference rather than repeating them all. (1) We request that the SDT replace "detect Faults on the BES Transmission System" with "protect the BES Transmission System" in all three places where it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry.
Response: Thank you for your comment. The drafting team used the term 'detect Faults on the BES Transmission System' to indicate those Protection Systems that may require review with other owners Protection Systems. The drafting team revised the phrase to read "installed for the purpose of detecting Faults on BES Elements" for consistency with the Facilities section of the Applicability. It is also noted that the identified interpretation was for the term 'transmission Protection Systems' which is not used in this Standard.		

Organization	Yes or No	Question 1 Comment
Western Small Entity Comment Group	Yes	
Imperial Irrigation District (IID)	Yes	
Midwest Reliability Organization NERC Standards Review Forum	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
National Grid and Niagara Mohawk (A National Grid Company)	Yes	
GP Strategies	Yes	
Luminant	Yes	
seattle city light	Yes	
Tennessee Valley Authority	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	
pacificorp	Yes	
Southern Company	Yes	
Dynegy	Yes	
Texas Reliablity Entity	Yes	

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	
Tacoma Power	Yes	
Entergy Services, Inc. (Transmission)	Yes	
City of Austin dba Austin Energy	Yes	
ITC	Yes	
Idaho Power Co.	Yes	
Sacramento Municipal Utility District	Yes	
Xcel Energy	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.

Response: Thank you for your support.

The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did

Organization	Yes or No	Question 1 Comment
revise some of the VSLs.		
Western Electricity Coordinating Council		We agree that unnecessary power system Elements should not be isolated to clear Faults, but question the statement that the "least number of power system Elements should be isolated." Reliability should be the goal. There may be situation where different isolation schemes both work, but perhaps one that isolates one or two more elements is more reliable.
Response: Response: Thank you for your comment. The Purpose has been revised based on your and others' comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		

2. The drafting team is proposing two definitions for use only with PRC-027-1 as follows: Interconnected Element: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity Protection System Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults. Do you agree with these definitions, if not please provide specific suggestions for change in the comment area.

Summary Consideration:

<u>Interconnected Element</u>

The following two items represent the majority of the comments: A) the use of the term Functional Entities; and B) the inclusion of a Registered Entity that represents multiple functional entities. As such, the drafting team revised the definition of Interconnected Element to:

Interconnected Element: A BES Element that electrically joins facilities owned by:
a) separate Registered Entities, or
b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

<u>Power System Study</u>

Several commenters disagreed with the definition of "Power System Study" and provided the following input: The term Power System Study (PSS) conflicts with a commonly used phrase for power system stabilizer used in generator excitation controls. The drafting team revised the term was revised to "Protection System Coordination Study". Some additional items were as follows:

1. The study is primarily for transmission facilities and Generator Owners should not be in the Applicability Section. The standard drafting team disagrees and stated in the reply that both entities are responsible and have a role in establishing Protective System coordination.
2. Figures 2 and 5 should be revised to clarify the scope of generator protection to be checked for proper coordination. The standard drafting team revised the language in Figure 2 and 5 to provide clarity.

3. Commenters requested additional clarification to identify the information required to properly demonstrate compliance of a study. The standard drafting team responded by indicating that Requirement R1 Section R1.2 was revised to state that the owner performing the PSCS must provide "a summary of the results of each Protection System Coordination Study performed pursuant to this requirement, (including, at a minimum, the Protection Systems reviewed, any issues identified, and any revisions proposed)." Along with the Protection Systems reviewed, the drafting team believes the minimum information that must be provided in a PSCS summary is the issues that were identified in the PSCS and any proposed revisions that were recommended as a result of the PSCS. Because most owners have their own unique Protection System setting philosophies and methods for performing a PSCS the drafting team believes providing a list of all the information that would comprise a PSCS would not be appropriate to include in Application Guidelines of this standard.

Organization	Yes or No	Question 2 Comment
Kansas City Power & Light	No	At our company there is one engineering group doing Protection System Studies for all Functional Entities and for multiple Registered Entities. Reliability is not enhanced by requiring a single engineering group to document and be audited for coordination with itself. An Interconnected Element should be defined as an element that electrically joins facilities that are controlled by separate operating companies and Protection Studies are done by separate engineering groups.
Response: Thank you for your comment. **The drafting team disagrees with your suggested definition of Interconnected Element.** **The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.**		
ACES Standards Collaborators	No	We recommend modifying the definition of Interconnected Element such that is dependent on actual registered entity ownership rather than functional entities. As an example, a generation Element would only be considered an Interconnection Element if the GO and TO were separate corporate entities. If the functions were the same registered entity, coordination would already occur and the generation Elements should not be considered an Interconnected

Organization	Yes or No	Question 2 Comment
		Element. To do otherwise will only cause significant compliance problems that may not support reliability. A utility that owns generation and transmission may not have a clear point of interconnection. This would be especially true for units installed prior to the advent of open access in the mid-1990s. If the point of interconnection is not well defined, how can an Interconnected Element be defined? It would be arbitrary to pick the GSU or an Element in the switchyard. Furthermore, focusing on ownership would actually make the proposed standard consistent with the existing PRC-001-2. That standard does not explicitly require coordination among different function entities within the same registered entity. Interconnection Element definition is proposing an administrative burden of having to coordinate within the same registered function. Documenting coordination efforts made to external functions is reasonable for reliability; however, keeping records of internal coordination is unnecessary. What would an entity be required to show if there was only one protection system engineer in the organization? Would that single person be required to document coordination among him/her self? We feel that this portion of the definition should be struck - it is more appropriate to clarify the coordination of protection system elements should be among external registered entities in the requirements. There should not be any requirement for internal protection system coordination, especially not in a definition.

Response: Thank you for your comment.

The drafting team revised the definition of Interconnected Element; however, we disagree with your example - just because the Transmission Owner and Generator Owner are part of the same Registered Entity does not necessarily mean the same technical groups are involved in the required Protection System Coordination Studies.

The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.

Organization	Yes or No	Question 2 Comment
American Electric Power	No	1. AEP recommends replacing all references to "generator Protection Systems" with "Generator Owner equipment that provides backup system protection", and suggest adding language to the standard for clarification. The scope of Generator Owner Protection Systems applicable to this standard is not clear from the verbiage within the standard or the definition of Interconnected Element. AEP believes that the SDT did not intend to require the GO to include all generator Protection Systems under this standard (as shown in Figure 2 on page 25 and Figure 5 on page 28 of the clean draft), but instead meant to limit the scope of relaying to be coordinated to only the Generator Owner equipment that provides backup system protection. 2. AEP agrees with the definition of Protection System Study, however, we disagree with using the acronym PSS within the standard as PSS is also the recognized acronym for Power System Stabilizer. Usage of this acronym (for example, in the Process Flow Chart) would cause unnecessary confusion.
Response: Thank you for your comments. **1. The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System components need to be coordinated between entities.** **2. The term Protection System Study (PSS) has been changed to Protection System Coordination Study (PSCS).**		
PPL Corporation NERC Registered Affiliates	No	As per this version, the standard's protection study requirement seems excessive. The definition of a Protection System Study needs to include identification of the party responsible for performing this work, which should be the TO for the reasons discussed above.
Response: Thank you for your comment. The drafting team believes that although the Transmission Owner may provide the majority of the data and work associated with this standard; however, the drafting team believes the Generator Owner shares the responsibility of ensuring the Protection Systems covered by this standard are properly coordinated.		

Organization	Yes or No	Question 2 Comment
CenterPoint Energy	No	CenterPoint Energy recommends the term “Protection System Study “ be defined as follows: “A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing postulated short circuit Fault events.”
Response: Thank you for your comment. The drafting team believes the definition as noted is sufficient.		
Sacramento Municipal Utility District	No	Clarification is necessary for the definition of “Interconnected Element” which requires the TO and GO function within a company to treat each other as if they were unrelated entities and apply all of this standard’s requirements.
Response: Thank you for your comment. **The drafting team revised the definition of Interconnected Element for clarity. A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).** **The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.**		
FirstEnergy	No	FirstEnergy supports the proposed definition for Protection System Study but believes the Interconnected Element definition requires some modification. As presently written the Interconnected Element definition appears to inadvertently omit coordination of two transmission owners that have tie-lines to each others systems. The two transmission owners are not "separate Functional Entities" but rather two Registered Entities performing the same functional entity (transmission owner) obligations. Additionally, it is understood that the intent is to also require Protection System

Organization	Yes or No	Question 2 Comment
		coordination at interconnection points where the point of interconnection may entail facilities owned by the same NERC Registered Entity having multiple functional entity classifications. FirstEnergy proposes the following definition for Interconnected Element: "Interconnected Element - An Element that electrically joins and interconnects facilities owned by a)separate Registered Entities, or b) the same Registered Entity, but includes those representing multiple functional entity (DP, GO or TO) responsibilities."
Response: Thank you for your comments. **The definition of Interconnected Element has been revised based on your and others comments to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		
Hydro One Networks Inc.	No	For Protection System Study: Suggest adding a phrase:"A study between two or more interconnected power system Elements that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults".
Response: Thank you for your comments. **The drafting team believes the existing definition is sufficient and declines to make the suggested change.**		
Liberty Electric Power LLC	No	Functional entity is not defined. System Studies should be defined as "a study performed by a TO that demonstrates.....etc."
Response: Thank you for your comments. **The definition of Interconnected Element has been revised based on your and others comments to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or**		

Organization	Yes or No	Question 2 Comment
b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner). The drafting team believes the existing definition of a PSCS is sufficient and that both parties have responsibility to coordinate.		
Northeast Power Coordinating Council	No	In the proposed definition of Interconnected Element "Functional Entities" is capitalized even though it is not in the NERC Glossary.
Response: Thank you for your comments. **The definition of Interconnected Element has been revised based on your And others comments to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		
SCE&G	No	SCE&G disagrees with the definition of "Interconnected Element". More clarity is needed regarding the language "Functional Entities that are part of the same Registered Entity". Entities that are vertically integrated and more specifically those vertically integrated companies that that have the same personnel performing the review of protection systems for the function of the TO and GO could be unnecessarily burdened if the definition were misconstrued to the point of requiring these personnel to display evidence of comparing studies with themselves.
Response: Thank you for your comments. **The definition of Interconnected Element has been revised to provide more clarity based on your and others comments to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		

Organization	Yes or No	Question 2 Comment
The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.		
seattle city light	No	Seattle City Light does not agree with the use of Functional Entity in the definition of Interconnected Element. Seattle has several objections. First, although “Functional Entity” is capitalized in the draft Standard, this term is not defined in the NERC Glossary of Terms. A second objection is that “Functional Entity” in this role does not add clarity to the Standard. “Functional Entity” is defined in the NERC Reliability Functional Model as “the term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function.” This definition refers to other terms defined only with the Functional Model document (“Task,” “Function”). It is not illuminating as to defining the bodies joined by Elements. The third and strongest objection is that use of the term “Functional Entity” in the proposed definition is incorrect and inconsistent with the NERC Functional Model, and as such creates confusion about Standard obligations for entities registered for more than one function. The NERC Functional Mode Version 5 (November 30, 2009) explicitly does not require any particular organization or assignment of functional Tasks or ownership of Elements for any multi-function entity. Functional tasks and Elements exist undifferentiated across an entity as a whole, and the NERC Functional Model document states clearly that no further differentiation is expected, required, or implied. (See, for example, p. 7 “The Functional Model describes a functional entity envisioned to ensure that all of the Tasks related to its Function are performed. The Model, while using the term ‘functional entity’, is a guideline and cannot prescribe responsibility” and p.8 “The Model is independent of any particular organization or market structure.”) Seattle City Light, for example, is a vertically integrated municipal utility registered for 11 functions: BA, DP, GO, GOP, LSE, PC, PSE, RP, TO, TOP, and TP.

Organization	Yes or No	Question 2 Comment
		Registration is made without differentiation: no particular sub-organization within Seattle City Light is identified as owning GO Elements, TO Elements, and so on. The Model is simply that Seattle City Light or any other multi-function entity owns a set of Elements s a unit. By contrast the draft definition relies upon differentiation of ownership of Elements within a multi-function entity, so that it can be determined if the proper studies were undertaken or not. Such differentiation is outside the Model and introduces complexities and unintended consequences not envisioned by the Functional Model and the term "Functional Entity." The same confusion about the term Functional Entity occurs in draft Standard COM-003-1. Seattle suggests that NERC immediately clarify the use of this term. Until the definition of the Functional Model is changed and changed significantly, the use of Functional Entity to define obligations within a Standard or definition (other than in the Applicability section) should be eliminated. As is it is simply a misreading, tempting as it may be, to presume that Functional Entity Tasks are assigned with greater granularity than to an organization as a whole. And it is a misreading that does not promote high quality Standards that can be consistently enforced across auditors and across regions. You can do better, and should do better. Seattle apologies that it does not have a suggested fix at this time, because the Functional Entity approach is so fundamentally wrong. Entitly (entirely?) new wording would be required to capture Elements existing within the same registerd Entity.
Response: Thank you for your comment. **The definition of Interconnected Element has been revised based on your and others comments to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		
JEA	No	Seems like Interconnect element is too broad and not enough clarity on what a

Organization	Yes or No	Question 2 Comment
		protective system study requires (Ie, is this a setting coordination study? Redundancy studies? Dynamic studies? Duplication of TPL requirements.
Response: Thank you for your comment. **The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).** **The drafting team changed the name from Protection System Study to Protection System Coordination Study.** **Note: The Guidelines and Technical Basis section of the Standard provides more information on the scope of a Protection System Coordination Study.**		
Imperial Irrigation District (IID)	No	Suggest replacing Protection System Study with Coordinated Protection System Study.
Response: Thank you for your comment. **The drafting team changed the name from Protection System Study to Protection System Coordination Study.**		
Certain Members of the ISO RTO Council	No	The definition of Interconnected Element is confusing since there are a mix of Functional Entities and Registered Entities, and some in the industry equate Functional Entities to Registered Entities. To avoid this confusion, we suggest replacing “Functional Entities” with “asset owners” or “facility owners.” If deemed desirable, the asset owners can be qualified by Transmission Owners, Generator Owners and Distribution Providers in parentheses The SRC asks if the definition for “Interconnected Facility” needs to be expanded to include situations where a Functional Entity may cross regional boundaries and have facilities that interconnect between the two, which may or may not be the same Registered Entity.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. **The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		
Independent Electricity System Operator	No	The definition of Interconnected Element is confusion since there is a mixture of Functional Entities and Registered Entities, and some in the industry equate Functional Entities to Registered Entities. To avoid this confusion, we suggest to replace Functional Entities with asset owners or facility owners. If deemed desirable, the asset owners can be qualified by Transmission Owners, Generator Owners and Distribution Providers in parentheses
Response: Thank you for your comment **The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		
Florida Municipal Power Agency	No	The definition of Interconnected Element limits the scope of the standard too much. The standard only requires coordination between neighboring entities and not of protection of other BES equipment within the same entity, e.g., one TO's transmission line protection with the protection of another transmission line owned by that same TO is not within the definition of Interconnected Element. It would seem that such a requirement would be necessary, e.g., each entity ensures that their protection internal to their system coordinates with itself, and that they coordinate at the boundaries with its neighbors. That would ensure coordination across the BES. Protection System Study definition should have a time element and a consideration for the critical clearing time, e.g., "and demonstrates that the resulting clearing time meets or beats the clearing time

Organization	Yes or No	Question 2 Comment
		used in studies to comply with the TPL standards" or something to that effect
Response: Thank you for your comment. **The drafting team has no evidence that there is widespread miscoordination of Protection Systems associated the BES and therefore the necessity of ensuring that Protection Systems internal to an owner's system should not be included in this standard. However, the drafting team believes that the scope of the standard should require that the individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination at the Interconnected Element.**		
ITC	No	1. The general idea of the Interconnected Element is acceptable. However, when one Registered Entity takes care of coordination between two Functional Entities, or coordinates all protection coordination between the two systems, the documentation will become onerous and not enhance the reliability of the BES. 2. The definition of the Protection System Study still needs further clarification. It is not clear what calculations/documentation must be kept to properly demonstrate compliance with the requirement of a "study." Past practice may have kept calculations and correspondence, which adequately demonstrate "evidence of coordination," but might or might not be adequate to a "protection system study" for future coordination efforts.
Response: Thank you for your comment. 1. **Just because the Transmission Owner and Generator Owner are part of the same Registered Entity does not necessarily mean the same technical groups are involved in the required Protection System Coordination Studies. The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.** 2. **The standard only requires that a summary of the results of each Protection System Coordination Study performed be provided; as such this would be the item to retain.**		

Organization	Yes or No	Question 2 Comment
American Transmssion Company, LLC	No	The Interconnected Element definition should be expanded to clarify that PRC-027 is applicable to only BES Elements as demonstrated in Figure 4 of the Standard's Application Guidelines on pg. 27. o ATC recommends that the SDT please modify the definition of Interconnected Element as follows:"A Bulk Electric System Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity" If "Functional Entity" is used and capitalized in the definition above, the term should be defined in the standard or be made part of the "Glossary of Terms Used in NERC Reliability Standards." Furthermore, NERC's "Reliability Functional Model version 5" states: "The following terms are used in the Functional Model and do not appear in the NERC Glossary. Functional Entity. The term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function."
Response: Thank you for your comment **The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		
Essential Power, LLC	No	1. The term Functional Entity needs a definition. It is capitalized in PRC-027 but is not defined in the standard or in the NERC Glossary. It is nonetheless evident that a GO and TO are different Functional Entities, but the nature of the Element that joins them and thereby constitutes the Interconnected Element is unclear. Is this the transmission line? If so, would the TO be responsible for the R1 study if the ownership scope of an independent GO ends at the high-side terminals of the GSU or at an HV

Organization	Yes or No	Question 2 Comment
		disconnect switch? Would the responsibility be shared if, as sometimes happens, the ownership split occurs at the fenceline, leaving a small part of the transmission line the property of the GO while the rest belongs to the TO? 2.The definition of a Protection System Study needs to include identification of the party responsible for performing this work. This cannot be the GO if dealing with a deregulated market; since, as explained above, such parties are not allowed access to information about the TO's system.
Response: Thank you for your comment 1. **The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by: a) separate Registered Entities, or b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).** 2. **The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the Generator Owner to ensure the Protection Systems covered by this standard are properly coordinated.**		
Cogentrix Energy Power Management, LLC	No	1.The term Functional Entity needs a definition. It is capitalized in PRC-027 but is not defined in the standard or in the NERC Glossary. It is nonetheless evident that a GO and TO are different Functional Entities, but the nature of the Element that joins them and thereby constitutes the Interconnected Element is unclear. Is this the transmission line? If so, would the TO be responsible for the R1 study if the ownership scope of an independent GO ends at the high-side terminals of the GSU or at an HV disconnect switch? Would the responsibility be shared if, as sometimes happens, the ownership split occurs at the fenceline, leaving a small part of the transmission line the property of the GO while the rest belongs to the TO?

Organization	Yes or No	Question 2 Comment
		2.The definition of a Protection System Study needs to include identification of the party responsible for performing this work. This cannot be the GO if dealing with a deregulated market; since, as explained above, such parties are not allowed access to information about the TO's system.
Response: Thank you for your comments. 1. **The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by: a) separate Registered Entities, or b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).** 2. **The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the GO to ensure proper coordination of the protection systems covered by this proposed standard.**		
GP Strategies	No	We do not believe that the drafting team appropriately identified the correct Applicable Functional Entities for this Standard. We also believe existing Standards could be modified to resolve any reliability gap rather than creating a new Standard. As a result, while the Purpose of this standard may seem to be reasonable, we feel that the drafting team should either 1) Change the Purpose to state "To conduct necessary studies to ensure Protection Systems for Interconnected Elements are studied, such that the least number or power system Elements are isolated to clear Faults." 2) And change the Applicable Functional Entities to the Transmission Planner or modify existing Standards, instead, as described below. The short-circuit studies should be conducted by the Transmission Planner. From Appendix 5B of the Registration Criteria the: o Transmission Planner is the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area." o Distribution Provider is the entity that provides and operates the

Organization	Yes or No	Question 2 Comment
		"wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage."TPL-001, TPL-002, and TPL-003 already require the system studies are conducted. These Standards should be modified to include any additional studies that the drafting team feels are a gap. As noted in the drafting teams Rational for Part R2.1 "Short circuit databases are customarily updated annually so the drafting team believes 24 months provides entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation." That being said, there is no current Requirement for the Distribution Provider to provide the information to the databases so that the Transmission Planner can conduct the studies on the Interconnection Facilities. We recommend that MOD-010 and MOD-012 should be modified to include the Distribution Provider instead. For new facilities, FAC-002-1 already requires the coordination of changes in the Facilities.
Response: Thank you for your comment. 1. **The drafting team revised the Purpose statement to: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.** 2. **The drafting team believes the Applicability as noted is correct. Although is some cases, some of the identified activities may be conducted by the Transmission Planner or other entities, it is the owners that are responsible for ensuring their Protection Systems are coordinated with others.**		
Public Service Enterprise Group	No	What information comprises a Protection System Study (PSS)? In the Application Guidelines, from Figure 1 on p. 24, each owner that receives a PSS is "to review the Protection System setting" associated with the other owner's breaker that would operate to clear a Fault on the transmission line that connects each

Organization	Yes or No	Question 2 Comment
		Interconnected Element. Is this (Protection System settings) the ONLY information that needs to be transmitted in a PSS by each owner? The SDT should itemize ALL of the information it believes needs to be included in a PSS that is to be transmitted between owners of an Interconnected Element and include that information in the examples in the Application Guideline. This information should also be listed into the PSS definition, thereby defining its scope.
Response: Thank you for your comments. **Requirement R1 Part R 1.2 of the standard has been revised to state that after completion of each Protection System Coordination Study (PSCS) the owner performing the PSCS must provide "a summary of the results of each Protection System Coordination Study performed pursuant to this requirement, (including, at a minimum, the Protection Systems reviewed, any issues identified, and any revisions proposed)." Along with the Protection Systems reviewed, the drafting team believes that the minimum information that must be provided in a PSCS summary are the issues that were identified in the PSCS and any proposed revisions that were recommended as a result of the PSCS. Because most owners have their own unique Protection System setting philosophies and methods for performing a PSCS the drafting team believes providing a list of all the information that would comprise a PSCS would not be appropriate to include in Application Guidelines of this standard.**		
Tacoma Power	No	1.Where is the term Functional Entity defined? 2.Consider changing the term Protection System Study to Protection System Coordination Study. There are two reasons for this recommendation. First, the abbreviation for Protection System Study is PSS, which is also the common abbreviation for power system stabilizer. Second, the term Protection System Coordination Study emphasizes the primary purpose of PRC-027-1: to coordinate Protection Systems.
Response: Thank you for your comment. **1. The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by: a) separate Registered Entities, or**		

Organization	Yes or No	Question 2 Comment
b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner). 2. The term Protection System Study (PSS) has been changed to Protection System Coordination Study (PSCS).		
Bonneville Power Administration	No	1.With regard to the definition of Interconnected Element, BPA believes the term should be interconnecting element, because the element is not interconnected, rather the systems of the functional entities are interconnected by the element. The point of interconnection between two functional entities is typically where two elements meet, such as between a line and a switch, and it is not a clear which element is the interconnected element. For example, suppose that a line from one entity terminates through a breaker at the bus of another entity's substation. Which is the interconnected element, the line, the breaker, or the bus? In another example, a generator ties to a transmission providers BES through a step-up transformer. Which is the interconnected element, the step-up transformer or the transmission line? Additionally, if a distribution provider taps off of a transmission provider's 230kV line through a disconnect switch, is the disconnect switch the interconnected element? BPA asks that the definition of Interconnecting Element be further clarified to provide the specific criteria that entities are expected to apply to come up with a consistent response in all such instances. The SDT attempted to illustrate the concept of the interconnected element through some examples in the Application Guidelines; however, the selection of the interconnected element in these examples neither follows logically from the standard nor provides the additional clarity necessary to enable industry participants to apply it in a manner that enables all users to come up with the same answers.. BPA believes the standard needs a clearer definition of an interconnected element. 2.With regard to the definition of a protection system study, the definition given

Organization	Yes or No	Question 2 Comment
		is too vague to provide a clear understanding of what is required by the standard.
Response: Thank you for your comments. 1. **The drafting team has provided examples of the applicable Interconnected Elements in the Figures at the end of the standard. This standard applies to the Protection Systems associated with the Interconnected Element installed for the purpose of detecting Faults on BES Elements and that require coordination for isolating those faulted Elements.** 2. **The term Protection System Study (PSS) has been changed to Protection System Coordination Study (PSCS) for clarity.**		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with question 2, we have the following general comments: (1) Please clarify why definitions are to remain with standard upon approval and not be moved to the Glossary. Are these definitions applicable only to this particular standard? If this is the case, this could lead to uncertainty if similar terms are going to be used or defined elsewhere. (2) Compliance 1.1 - The word 'Compliance' in the first line should not be capitalized and (CEA) should follow the word 'authority'. Since 'Regional Entity' is a defined term, 'Entity' needs to be capitalized. (3) Compliance 1.2 - The second paragraph should begin with 'Each', not 'The'. We suggest that the reference to an 'Interconnected Facility' in the second paragraph should be changed to 'a Facility associated with an Interconnected Element' to make it consistent with the rest of the standard, including the third paragraph of 1.2.
Response: Thank you for your comments. 1. **Yes, the definitions are intended for use only in this standard.** 2. **The noted corrections have been made.** 3. **The noted corrections have been made.**		

Organization	Yes or No	Question 2 Comment
Texas Reliablity Entity	Yes	The SDT may want to consider additional language for the Protection System Study definition, to clarify that the study demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults as well as clear the Faults within the maximum time frame defined by the Transmission Planner in order to maintain System Stability. Another consideration would be that the study incorporates all of the applicable Fault contingencies (Category B and C) as defined in the NERC Reliability Standards (TPL-002 and TPL-003) or any Regional standards.
Response: Thank you for your comments **The drafting team believes the definition as stated is sufficient.**		
Duke Energy	Yes	The SDT should consider putting the definition of Interconnected Element in the NERC Glossary.
Response: Thank you for your comment; **The drafting team intends for this definition to be used only with this standard.**		
Southwest Power Pool Reliability Standards Development Team	Yes	1. Under figure 2 in the application guidelines the example need to be reviewed and text added to clearly identify the intent of the drafting team. For example is the scope for Generator Owners in figure 2 just the backup system protection for the Transmission Owners system? It's not clear in the examples given. This issue is also present in figure 5. We agree that if the scope is just for the backup system protection it is ok but the wording does not clearly state this. 2. Also using PSS as an acronym for Protection System Study could be confused in the flowchart of this standard with power system stabilizers since there isn't any text to spell out that it is referring to Protection System Study.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. 1. **The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System components need to be coordinated between entities.** 2. **The term Protection System Study (PSS) has been changed to Protection System Coordination Study (PSCS) for clarity.**		
Western Electricity Coordinating Council	Yes	We agree with the definitions, but question the appropriateness of development of terms for a specific standard. Individual Regions are strongly discouraged from defining terms that only apply in a single region. We see the development of a term that is only applicable to a single standard to be a similar situation, leading to a proliferation of terms. If this approach is acceptable to NERC and FERC, we have no concerns.
Response: Thank you for your comment. **This approach is consistent with NERCs standards drafting guidelines.**		
Pepco Holdings Inc & Affiliates	Yes	
Western Small Entity Comment Group	Yes	
Midwest Reliability Organization NERC Standards Review Forum	Yes	
National Grid and Niagara Mohawk (A National Grid Company)	Yes	
Luminant	Yes	
Dominion	Yes	

Organization	Yes or No	Question 2 Comment
SERC Protection and Controls Subcommittee (PCS	Yes	
Tennessee Valley Authority	Yes	
US Bureau of Reclamation	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	
pacificorp	Yes	
Southern Company	Yes	
Dynegy	Yes	
Ingleside Cogeneration LP	Yes	
Wisconsin Electric Power Company	Yes	
Ameren	Yes	
Entergy Services, Inc. (Transmission)	Yes	
City of Austin dba Austin Energy	Yes	
Idaho Power Co.	Yes	
Nebraska Public Power District	Yes	
Georgia Transmission Corporation	Yes	

Organization	Yes or No	Question 2 Comment
Xcel Energy	Yes	
City of Tallahassee	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.

Response: Response: Thank you for your support.

The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise some of the VSLs.

3. In Requirement R1, the drafting team modified the time frame to allow entities 48 months to have a documented Protection System Study completed for each Interconnected Element if no Protection System Study exists. Note, the drafting team has allowed inclusion of all previously performed Protection System Studies whose summary of results include, at a minimum, the protective relay settings reviewed, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.

Summary Consideration:

Some commenters stated that 48 months in Requirements R1 part 1.1.1 was not enough time for the initial study to be complete. The drafting team revised the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.

A few commenters stated that checking Fault currents and calculating a percent deviation in Requirements R2 part 2.1 ever 24 months was too often. The drafting team revised the timeframe to 60 calendar months, and added the provision that this was not necessary if there was a technical justification why periodic Fault current studies are not necessary for the coordination of Protection Systems associated with Interconnected Elements.

A few commenters requested that the percent deviation trigger in Requirements R1 Part 1.1.2 and Requirement R2 Part 2.2 be changed to 20%. The drafting team left the 10% trigger as an appropriate value.

A few commenters requested that the initial study in Requirements R1 Part 1.1.1 be moved to the implementation plan. The drafting team investigated this as an option but did not make this change. The drafting team stated that it believes the structure of Requirement R1, Part 1.1.1., as currently written, achieves this goal.

A request was made to clarify that an entity was only responsible for performing studies on their Protection System. The drafting team has modified the language of the requirement to read: “Perform a Protection System Coordination Study for each of its Interconnected Elements…”

A request was made to clarify where the 10% threshold in Requirement R1 Part 1.1.2 and calculated in Requirement R2 Part 2.1.2 is applied. The drafting team responded that Requirement R2, Part 2.1.1 refers to maximum available current at the interconnecting bus (total bus fault current). The drafting team has included clarifying language in the Rationale for Requirement R2, Part 2.1 and in the language of Requirement R2, Part 2.1.2 to indicate the need to compare both line-to-ground and three-phase fault current values when performing the calculation to check for a ±10% deviation.

There was a comment asking if a study was performed as a collaborated effort would the acceptance of the results of the study be acceptable. The drafting team stated they recognize that in many cases the owners may do joint studies; but both entities would need to agree with the results of the Protection System Coordination Study for it to be acceptable.

A commenter stated that confirmation from both parties that coordination has been reviewed should be adequate evidence that an entity is in compliance with the standard. The drafting team stated that they believe all Requirements included in this standard support its reliability objective, however Requirement R4 Part 4.2 the standard has been modified to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.

A few commenters stated that Requirement R1 should not apply to Generator Owners. Because Generator Owners are not allowed to have the Transmission Owners information needed for a system study under market rules. The drafting team stated that they do not believe that the Transmission Owner is restricted from providing the Protection System data necessary for the Generator Owner to ensure proper coordination of Protection Systems applicable to this proposed standard.

A few commenters requested clarification as to what comprises a valid PSS. In response, the drafting team has refined the examples given in Requirement R1, Part 1.2 of the minimum information required in a summary of the results of a Protection System Coordination Study (PSCS).

One commenter asked if previous studies were satisfactory to meet the requirements. The drafting team stated that they believe that a previous study can be used as a basis of a summary that includes all the needed information and send it to the other party to review after the effective date of the standard?

Organization	Yes or No	Question 3 Comment
Kansas City Power & Light	No	1. Proposed Requirement R1 allows 48 months to do an initial study with the explanation that there is no evidence of widespread miscoordination. We agree that there is no evidence of widespread miscoordination and therefore 60 months is the proper time frame for an initial study. 2. We have also noticed that there is no question on this comment form for any

Organization	Yes or No	Question 3 Comment
		other comments not addressed by the drafting teams questions. As such we note here that Requirement R1, 1.1.2 lists a 10% change in current as an action point. This implies that a 10% decrease requires action. We do not agree with this since most Protection Studies are done with all generation on. Most of the year all generation is not on with the result that normal operating conditions result in fault currents that are 10% below the maximum used in the Protection System Study. We also disagree with action required for a 10% increase in fault current since our standard relay settings no longer trip for instantaneous ground over current elements and the standard does not allow an entity to state a reason not to run this study or perform the calculations. When we did utilize instantaneous ground over current elements we allowed a 40% margin. We utilize other high speed protection elements not directly affected by changes in fault current. We recommend at least a 20% change in fault current to require action per this standard. 3. Requirement R2 requires that a short circuit study be done every 24 months. As noted above 60 months is proper time for initial study and is also proper for subsequent studies done after the initial study is complete.
Response: Thank you for your comment. 1. **Based on stakeholder comments, the drafting team revised the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.** 2. **The drafting team believes, as noted in the rationale, that the ±10 % change is an appropriate threshold to trigger investigation of the need for a review of Protection Systems. This does not require a new Protection System Coordination Study if an entity provides a technical justification demonstrating why a new study is not necessary.** 3. **The drafting team revised Requirement R2 to require, at least once every 60 calendar months, Transmission Owners perform a short circuit study and calculation of fault current deviation for its Interconnected Elements or provide a technical justification why periodic fault current studies are not necessary for the coordination of Protection Systems associated with Interconnected Elements.**		
ACES Standards Collaborators	No	(1) While we do not disagree with the time frame, we question if it should be

Organization	Yes or No	Question 3 Comment
		part of the requirement. It makes more sense to include the time frame for initial compliance of a requirement in the implementation plan. In that way, the initial compliance time frame does not persist in the standard long after it is no longer needed. It is common to utilize the implementation plan to describe initial compliance dates, especially when the requirement is asking for documented studies. After the studies are complete, there is not a need for a timeframe. Furthermore, FERC approves implementation plans as part of the standards package so there is no issue with whether the implementation plan is enforceable. (2) Conceptually, we agree with the intent of the standard and this requirement as it is presented in the application guidelines. However, more refinement is needed to make this requirement mirror what is explained in the application guidelines. For instance, we recommend clearly stating in Requirement R1 that the responsible entity is only responsible for performing Protection System Studies (PSS) for only those breakers it owns and are protecting the Interconnection Element. The standard is close to capturing this intent with the statement “its System” in Part 1.1. It would be better it if was changed to “Perform a Protection System Study for each of its Protection Systems that are protecting an Interconnected Element.” A GO and DP do not really have systems so the current language is not appropriate for these functions. The application guidelines provide this clarity and would be helpful if the intent was clearly stated in the requirements.

Response: Thank you for your comment.

1. **The drafting team agrees your suggestion provides one way of addressing initial requirements to have documented Protections System Coordination Studies for each Interconnected Element. However, the drafting team believes the structure of Requirement R1, Part 1.1.1, as currently written, achieves this goal. Further, NERC performs periodic review of standards and the requirement can be removed at that time, if appropriate.**
2. **Based on your suggestion, the drafting team has modified the language of the requirement to read: “Perform a Protection**

Organization	Yes or No	Question 3 Comment
System Coordination Study for each of its Interconnected Elements…".		
CenterPoint Energy	No	(a) CenterPoint Energy continues to believe a requirement to have a documented Protection System Study for each existing Interconnected Facility is overly burdensome, unless certain - if not all - existing Interconnected Facilities are exempted; therefore, CenterPoint Energy recommends R1.1.1 be eliminated from PRC-027-1. CenterPoint Energy does not believe a reliability need has been identified to justify that such prescriptive requirements are needed to provide for an adequate level of reliability. The following is stated on page 18 of 28 in PRC-027-1 Draft 2: "records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations." The majority of existing Interconnected Facilities have fault-proven, time-proven protection system set points. An existing Interconnected Facility without a documented Protection System Study will eventually be included in a study with system additions and changes, short circuit current increases, and relay panel replacement projects, as well as any analysis of misoperations. (b) While an option has been included in Draft 2 R1.1.3 to allow for a technical justification why a study is not required for certain changes, CenterPoint Energy believes that reasonable thresholds should be established for the changes identified in R3.1. For example, R3.1 requires that "any" change of sequence or mutual coupling impedance must be provided to a Generator Owner. For insignificant changes of sequence or mutual coupling impedance, CenterPoint Energy believes there would be little, if any, reliability benefit of communicating and technically justifying why a study is not required.

Response: Thank you for your comment.

a) **The drafting team believes that there is a reliability benefit in ensuring that all existing Protection Systems on Interconnected Elements have been reviewed. The drafting team acknowledges the fact that no immediate reliability concern has been identified and, as such, has allocated an extended time to complete this work.**

Organization	Yes or No	Question 3 Comment
b) The drafting team believes that information about any change (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the Interconnected Element.		
FirstEnergy	No	A) FirstEnergy supports the 48 month timeframe to complete initial Protection System Studies. However, based on the fact that the drafting team may have overlooked system tie points of two transmission systems (see our response to Q2) the completion of Protection Studies may require additional time. B) FE could support a 48 month implementation and encourages the drafting team to consider a staggered plan that requires earlier completion for higher voltage systems. For example, 1) systems operated at 300kV and higher within 24 months, 2) systems operated at 200kV and higher up to 300kV within 36 months and 3) systems operated at 100kV and higher up to 200kV within 48 months. C) As expressed in FirstEnergy's Draft 1 comments, we do not support requirement text that is better placed in an Implementation Plan. A requirement should be written such that it is everlasting. As written, R1 part 1.1.1. has no meaning after the 48 month period expires. D) It is FirstEnergy's experience that the Transmission Owner would likely have the expertise and staff to perform the desired Protection System Study. The team should consider whether or not the DP and GO would typically be performing their own independent study or collaborating with the TO in a supporting role by providing data and reviewing study results. In regard to items B) and C) FirstEnergy proposes the following for Requirement R1. **Start of proposed requirement R1 text **R1. Each Transmission Owner shall perform a Protection System Study for each Interconnected Element on its System associated with a Generator Owner, Distribution Provider or another Transmission Owner. Each study shall include at a minimum: [Violation Risk

Organization	Yes or No	Question 3 Comment
		Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning] - the protective relay settings reviewed - power system Elements to be isolated - contingencies evaluated - Fault currents used - any issues identified - any revisions proposed 1.1. Each Transmission Owner shall update its Protection System Study: 1.1.1 Within six calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. 1.1.2 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 or Part 3.3, or technically justify why such a study is not required. 1.2. Within 90 calendar days after the completion of each Protection System Study the Transmission Owner shall provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement.**End of proposed requirement R1 text ** E) FirstEnergy recommends that for ease of ordered reading that the numbering of Measures be tied to the Requirement number. For example Requirement R1 has two measures M1 and M2. Consider renumbering to M1.1 and M1.2.

Response: Thank you for your comment.

A) The drafting team does not agree that it has overlooked the Transmission Owner to Transmission Owner interconnections in the Interconnected Element definition. However, it has been modified as follows: A BES Element that electrically joins facilities owned by:
a) separate Registered Entities, or
b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

B) Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar

Organization	Yes or No	Question 3 Comment
months. The drafting team chose not to prescribe how an entity achieves compliance with this requirement; however, an entity may implement its own phased in approach within the confines of a 60 calendar month maximum time frame. C) The drafting team recognizes that your suggestion provides one way of addressing the requirement to have documented Protections System Coordination Studies for each Interconnected Element. However, the drafting team believes the structure of Requirement R1, Part 1.1.1, as currently written, achieves this goal. Further, NERC performs periodic reviews of standards and the requirement can be removed at that time, if appropriate. D) The drafting team recognizes that in many cases the Protection System Coordination Study may be a collaborated effort; but, ultimately it is the owner's responsibility. E) The format used in this standard is consistent with the current NERC standards development process.		
Sacramento Municipal Utility District	No	"The results based objective is that the registered entities communicate and coordinate with each other. A simple statement by both entities that they have reviewed each other's settings and agree they coordinate is sufficient proof that the reliability objective of this standard is met." Performance of a PSS is an intermediate step toward achieving coordination. It does not improve reliability if an entity does not act on it. Only in the final step - when agreed upon changes are made - does system reliability actually improve. The standard should consist of R3.1 (one side makes a change which triggers a review), followed by R4.2 (all parties agree to the changes to be implemented). Documenting the process steps between these two points in time does not improve system reliability.
Response: Thank you for your comment. **The drafting team believes all requirements included in this standard support its reliability objective.**		
American Electric Power	No	AEP believes that 48 months to complete a Protection System Study is too short of a time frame, especially for Interconnected Elements which do not have an existing study. NERC's rationale for R1 states that "the drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame." If this is the case, then there should be no issue with extending this timeframe. AEP believes

Organization	Yes or No	Question 3 Comment
		that 72 months is a more reasonable timeframe for the following reasons: * The Transmission Owner will need to complete their own studies, as well as provide data to the entities they interconnect with (i.e. TO's, GO's, and DP's). This dependency would effectively shorten the amount of time the functional entity has to complete their studies to less than 48 months. * Before the work of the first bullet point above can be completed, entities must develop an agreed-upon list of Interconnected Elements and associated owners of the Protections System(s) associated with each Element. Once again, the time required to complete this task erodes into the entire time allowed to perform the study. In short, much of this work must be sequentially rather than in parallel, further justifying the need for an increased timeframe. * The resources needed to complete the required studies will also be impacted by a number of other standards currently in draft including: PRC-006-1, PRC-019-1, PRC-024-1, PRC-025-1 and PRC-004-3. The work required to perform both the proposed studies of this standard, as well as the other standards listed above, requires a Subject Matter Expert possessing a specific skillset gained from years of protection experience. Due to the limited number of such SMEs, industry will be very challenged in meeting all the proposed requirements given the limited number of such resources. In addition, the demand for qualified outside resources might be greater than their actual availability due to the time constraints involved.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team revised the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Salt River Project	No	Agree with timing, but confirmation from both parties that coordination has been reviewed should be adequate evidence.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
The drafting team stated that they believe all requirements included in this standard support its reliability objective, however Requirement R4 Part 4.2 the standard has been modified to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.		
Florida Municipal Power Agency	No	As worded, R1 seems to require two neighboring entities to perform independent studies. We would hope that the intent of the drafting team is to allow any one entity to do a study and then the neighboring entity accept the results of that study, or to perform a joint study. We suggest the drafting team make conforming changes to allow this.
Response: Thank you for your comment. **The drafting team recognizes that in many cases the owners may do joint studies; but both entities would need to agree with the results of the Protection System Coordination Study. After the initial assessment, the Transmission Owner is the entity required to perform future, periodic fault current studies.** **It is also recognized that, in most cases, it will require a collaborative effort to complete the studies; but ultimately, it is the owners' responsibility to ensure that the requirements of this standard are met.**		
ATCO Electric	No	ATCO Electric (AE) has an existing protection review program that runs on 5 year cycle. Each year, AE review approximately 20% of AE's transmission system to ensure the protection is in place or needs adjustment. Can the drafting team increase 48 month duration to 60 months?
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Bonneville Power Administration	No	BPA believes that the requirement to provide a protection system study for each interconnected element is onerous, and as a result, any amount of time is too

Organization	Yes or No	Question 3 Comment
		short.
Response: Thank you for your comment. **The drafting team believes that there is a reliability benefit in ensuring that all existing Protection Systems on Interconnected Elements have been reviewed. The drafting team acknowledges the fact that no immediate reliability concern has been identified and as such has allocated an extended time to complete this work.**		
Luminant	No	Comment on Requirement R1.2. The time frame listed may not be adequate under all circumstances or situations. Luminant recommends that the language be changed in this requirement as follows: "... Protection System Study performed pursuant to this requirement (including at a minimum, the Protection System(s) reviewed, any issued identified, and any revisions proposed) shall be within 90 days or in accordance to an agreed-upon schedule with a Transmission Owner, Generation Owner, or Distribution Provider." This would align with R4.1 that also provides the same time frame. The corresponding measures will also need to be modified if this language is accepted.
Response: Thank you for your comment. **Requirement R1, Part 1.2 requires entities to provide a summary of results of a Protection System Coordination Study (PSCS) to affected entities within 90 days of completion of such a study. Requirement R4, Part 4.1 provides an additional 90 days (or according to an agreed upon schedule) for the recipient of the summary results to review and respond. Considering the 90-day time frame begins after the completion of a PSCS, and only addresses the amount of time allotted to provide a summary of the study to another entity, the drafting team believes there is no need to add the caveat of "an agreed upon schedule" to the 90-day time limit.**		
Western Electricity Coordinating Council	No	Creating a Protection System consists of conducting Protection System studies and incorporating the data into an entity's transmission/generation/distribution system. Protection System studies are not a new concept to entities. In the event that an entity discovers that certain interconnected elements are not included in the Protection System study the entity should not require 48 months

Organization	Yes or No	Question 3 Comment
		to make the needed changes to the study. From a reliability perspective, entities should already have a basic Protection System study in order to have a Protection System. Allowing an additional 48 months creates a potentially large 4 year reliability gap based on entities existing studies and any needed corrections. From a compliance perspective, allowing a 48 month time frame for entities to have a documented Protection System study effectively pushes mandatory compliance for this standard out for an additional four years beyond the effective date. This time frame is excessive and should be reduced to no more than 24 months from the effective date of the standard.
Response: Thank you for your comment. **Based on stakeholder comments, and recognizing there is no evidence of widespread miscoordination of Protection Systems associated with Interconnected Elements, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Northeast Power Coordinating Council	No	Due to the extensive documentation, coupled with the collaboration between entities associated with this requirement, NPCC believes 60 months is a more appropriate time frame to comply. This timeframe is also more in line with the timeframe proposed in the draft PRC-019-1 in Project 2007-09. An alternative to the "static" time frame discussed above, which would also be acceptable, would be to base the timeframe on a formula that factors in the number of interconnected power system elements that the entity must contend with.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Pepco Holdings Inc & Affiliates	No	Each owner should already possess information demonstrating that their protective devices are set to “coordinate” with adjacent protection systems. However, the documentation that presently exists may not be in the form of a

Organization	Yes or No	Question 3 Comment
		formal “coordination study” in a format suitable for audit purposes. Some guidance should be provided indicating what form of documentation is expected, especially by the TO. For instance, on transmission tie lines between different TO’s coordination of zone distance elements is fairly straightforward and can be accomplished without a traditional “coordination study”. Also settings on pilot schemes need to be exchanged in order to allow for proper operation, but this is also not what is considered a traditional “coordination study”. On the other hand, coordination between GO’s and TO’s is even more complicated. Without some direction as to what specific documentation is required it is difficult to estimate how many existing interconnection points would have to be re-visited in order to produce the required auditable documentation. Some specific examples of what specific type of documentation is required would be helpful. To be safe, most likely all interconnection points would be revisited to ensure adequate compliance documentation. Also, for each revised Protection Study produced (per R1.1) a formal review (R1.2) and approval (R4.1) would be required. As such, with the large number of interconnection points on the system a 60 month time frame would be more appropriate. The drafting team acknowledged that they had no evidence that there is widespread miscoordination between Interconnected Facilities when establishing the arbitrary 48 month requirement.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.** **Note: Acceptable evidence (per Measure M1) is a Protection System Coordination Study (PSCS) or a summary of the results of the PSCS.**		
Southern Company	No	For large entities with hundreds of generators, a longer initial time frame is needed. In addition, consideration should be given to the fact that existing transmission protection and control engineering personnel will be fully engaged

Organization	Yes or No	Question 3 Comment
		in the work associated with FERC order 754 for The next 12+ months.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Georgia Transmission Corporation	No	Guidelines and Technical Basis Req. R1: "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults."......These studies may include graphical coordination....; relay scheme simulation studies....; and sensitivity studies using sequence...., and adequate directional polarizing quantities. This activity will be onerous without a full system model and software to perform studies that would check coordination of stacked curves and stepped distance relays. Of particular note is the question of adequate directional polarizing quantities. There should be an expected minimum requirement such as time overcurrent plots and zone distance plots of the existing relay settings for the terminal with the fault points used as the basis. This data would then be used to indicate if the 10% point has been reached that would require a new coordination follow up at the end of the next 24 month fault study.
Response: Thank you for your comment. **Acceptable evidence (per Measure M1) is a Protection System Coordination Study (PSCS) or a summary of the results of the PSCS. The ±10% threshold relates to the fault current at the interconnected bus; not individual relay tolerances.**		
National Grid and Niagara Mohawk (A National Grid Company)	No	How would "fault currents used" be presented for coordination of distance relays ? Also if the above items must be included, at a minimum, they need to be enumerated in requirement R1.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
Each company must determine proper use of fault currents for their particular Protection System components. The language of the Requirement R1, Part 1.2 has been modified to indicate "(including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions proposed)".		
Hydro One Networks Inc.	No	Hydro One believes 60 months is a more appropriate time frame to conduct, document and obtain consensus for a protection system study. This timeframe is also more in line with the timeframe proposed in the draft PRC-019-1 in Project 2007-09. Large entities and small entities have the same time frame to complete this work which seems unreasonable. Alternatively, an extended period should be provided based on a formula that factors the quantity of interconnected power system elements.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Ingleside Cogeneration LP	No	Ingleside Cogeneration, like many other Generator Owners, does not typically perform fault studies unless we have made material changes to our transmission system interconnection. Even then, we provide modeling data to the appropriate Transmission Owners and Transmission Planners, who execute the assessments on a Regionally-standardized platform. We are not convinced that we can add value to this process - other than to demonstrate that the information required by the TO and TP was provided, and the study took place. In our view, the requirement should clearly accommodate this working arrangement. As it reads now, it seems like both the GO and the TO must perform separate assessments. The extra costs that we will incur to commission external consultants is difficult to justify when there are so many other pressing priorities (e.g.; cold weather preparedness).
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
The drafting team recognizes that in many cases the owners may do joint studies; but both entities would need to agree with the results of the Protection System Coordination Study. After the initial assessment, the Transmission Owner is the entity required to perform future, periodic Fault current studies. **It is also recognized that, in most cases, it will require a collaborative effort to complete the studies; but ultimately, it is the owners' responsibility to ensure that the requirements of this standard are met.**		
Dynegy	No	Perhaps R1 could be reworded to answer the following question: "If an entity registered only as a GO owns relays that trip the generator alone (and not relays detecting a fault on any transmission lines), does this Standard apply?"
Response: Thank you for your comment. **Per the Applicability section of the standard, if the Generator Owner owns no Protection Systems that require coordination with other owners, then the standard would not apply to those Protection Systems.**		
Portland General Electric Co	No	Portland General Electric Company appreciates the drafting team's consideration of comments. Since there wasn't a general comment section at the end of this form, the discussion of timeframes seems appropriate here. The effective date (the first quarter six months after approval) does not allow sufficient time for compliance. This standard will require that entities include in all interconnection agreements a detailed protection coordination schedule or be subject to the long timelines detailed in the standard. None of the agreements (if they even exist) for projects six months out include a protection coordination schedule, nor do their project schedules accommodate the long durations detailed in the standard. Agreements will also need to be drawn up for smaller projects in order to document a protection coordination schedule, lest the interconnecting utility prevents us from energizing by taking the full 90 days to review the relay settings. In addition, entities may need at least one additional resource to conduct the bi-annual coordination studies and manage the interconnection due dates. PGE suggests an implementation period of 24

Organization	Yes or No	Question 3 Comment
		months since planning is done more than a year in advance.
Response: Thank you for your comment. **The drafting team believes the elements of Requirement R3 provide sufficient flexibility for project scheduling with regard to achieving proper Protection System Coordination prior to energization.** **Based on stakeholder comments, the drafting team has extended the timeframe for Requirement R1, Part 1.1.1 and the periodic Fault current study to 60 calendar months.**		
Liberty Electric Power LLC	No	R1 should not apply to GOs. GOs are not allowed to have the TO information needed for a system study under market rules.
Response: Thank you for your comment. **The drafting team does not believe that the Transmission Owner is restricted from providing the Protection System data necessary for the Generator Owner to ensure proper coordination of Protection Systems applicable to this proposed standard.**		
ReliabilityFirst	No	ReliabilityFirst abstains and offers the following comments for consideration: 1. Requirement R1, Part 1.1.1a. ReliabilityFirst questions the rationale for the 48 calendar month window to perform a Protection System Study if NO study exists. ReliabilityFirst believes that a Protection System Study is one of the fundamental reasons for the standard and believes if NO study had ever been performed, one should be performed as soon as possible (12 months). Within the rationale section, the drafting team states: "The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame." With no widespread mis-coordination of protection systems, ReliabilityFirst questions the actual need for the standard itself. 2. It is not clear where the 10% threshold in Part 1.1.2 and calculated in Part 2.1.2 is applied. Does the 10% threshold apply to the total bus Fault current at the interconnecting bus or the contributing Elements? If it is the total, then

Organization	Yes or No	Question 3 Comment
		there are situations where some of the sources into the bus may change their contribution quite a bit more than the 10% threshold but yet the total change could be less than 10%. Protective relaying is set in reference to the Element it is protecting or, to be more precise, the instrument transformers associated with an Element. The 10% threshold should be applied to the Interconnecting Element as its contributing quantities could change significantly even if the total Fault current stayed nearly the same. It is the Fault quantities on the Element that the interconnection protection sees - not the total bus Fault current (unless the Interconnecting Element is a bus). It is also not clear which phase or sequence currents are being used in the %Deviation calculation. Is it 3I0 (3 times zero sequence) current for single line to ground Faults and I1 (positive sequence) current for 3-phase Faults? It should be noted that if variations in Fault current of 10% are acceptable, then entities may need to adjust their criteria to use margins of 15% or more to consider other sources of error such as relay and instrument transformer accuracy.
Response: Thank you for your comment. 1. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months. Additionally, the drafting team believes there is a reliability benefit to require that all interconnected Elements have a valid Protection System Coordination Study in order to ensure coordination between owners of interconnected Elements.** 2. **Requirement R2, Part 2.1.1 refers to maximum available current at the interconnecting bus (total bus fault current). The drafting team has included clarifying language in the Rationale for Requirement R2, Part 2.1 and in the language of Requirement R2, Part 2.1.2 to indicate the need to compare both line-to-ground and three-phase fault current values when performing the calculation to check for a ±10% deviation.**		
Entergy Services, Inc. (Transmission)	No	Request consideration in replacing the time increment of 48 months with 4 years for the time frame.
Response: Thank you for your comment. **The drafting team has retained the use of months; however, the drafting team has modified the timeframe for Requirement R1,**		

Organization	Yes or No	Question 3 Comment
Part 1.1.1 to 60 calendar months.		
PPL Corporation NERC Registered Affiliates	No	Sixty months would be more appropriate to study all the interconnections. There has not been a major problem with mis-coordination of Protection Systems associated with Interconnected Elements. Also, the standard does not fully address what all should be included in a Protection System Study.R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
ITC	No	The amount of work required to comply with this requirement may be significant and may impact ongoing efforts to upgrade and improve the system. The above items that need to be documented can often be discussed and agreed to verbally between parties and are were often not part of a permanent record. The additional record keeping required may be significant and not add to the reliability of the BES.
Response: Thank you for your comment. **The drafting team does not believe a verbal agreement is measurable or auditable.**		
Western Small Entity Comment Group	No	The comment group agrees that Protection Systems associated with Interconnected Elements must be coordinated. However, the reliability goal should be strictly focused on documenting the associated owners (parties) are cooperating, and in agreement with protection settings to achieve proper coordination. A requirement to have a documented Protection System Study completed will not improve on a simple statement from the parties that proper coordination has been agreed upon. Provision of a Protection System Study as

Organization	Yes or No	Question 3 Comment
		compliance evidence (in whole or a summary) implies recourse to check its completeness or accuracy. For complex systems, this is very subjective. However, the Standard as written intends to make no effort to verify the completeness or accuracy of a Protection System Study; the intent is to simply verify that it exists. Since the Protection System Study is not subject to review, its production as compliance evidence is nothing more than added bulk.
Response: Thank you for your comment. **Acceptable evidence (per Measure M1) is a Protection System Coordination Study (PSCS) or a summary of the results of the PSCS. Minimum elements required in the summary results are provided in Requirement R1, Part 1.2. It is the responsibility of the respective owners to ensure the accuracy and completeness of the study results.**		
Public Service Enterprise Group	No	The issue is consistency in what comprises a valid PSS. For example, for "contingencies evaluated," it seems that each owner should evaluate a core set of the same contingencies as opposed to this being an owner-by-owner decision. The lack of specificity as to what is required for a PSS is the issue.
Response: Thank you for your comment. **A Protection System Coordination Study (PSCS), by definition within PRC-027, must demonstrate that existing or proposed Protection Systems operate in the desired sequence for clearing Faults. Most entities have internal procedures regarding the performance of coordination studies that produce the results required, but may not involve the exact same process or procedures that another entity follows to achieve Protection System coordination. The drafting team chose not to specifically dictate the elements of this process, but rather to continue to allow entities to "demonstrate that existing or proposed Protection Systems operate in the desired sequence for clearing Faults" according to their own internal procedures.** **The examples of information required in a "summary" of the results of a PSCS represent a minimum set of data that must be provided so the receiving entity can effectively assess coordination of the system. The drafting team has revised the examples to add clarity and the particular example provided in your comment has been removed.**		
Midwest Reliability Organization	No	The NSRF recommends that this Standard be filtered through the paragraph 81

Organization	Yes or No	Question 3 Comment
NERC Standards Review Forum		criteria. If not, the NSRF recommends the following items. 1. Although supportive of the extended timeframe in R1, the NSRF is concerned that the proposed Part 1.2 is overly prescriptive. Considering the sheer quantity of microprocessor relay settings that could potentially be reviewed as part of a Protection System Study, having to provide associated owner(s) the results of every protective relay setting reviewed would be unnecessarily burdensome with little benefit to reliability. Recommend the drafting team revise Part 1.2 to require entities to only provide information related to settings being proposed for change and have all other settings be made available upon request. 2. Please clarify the application of R1, Part 1.2 in the event that both ends of the Interconnected Element are owned by the same entity. In consideration that final settings and internal documentation would provide proof that everything was looked at accordingly, would the entity still need to develop and distribute a summary internally as well? Recommend revising Part 1.2 to only require functionally separate entities to provide documentation of the results of the Protection System Study. 3. Rather than specify the details to be shared as a result of a Protection System Study, recommend Part 1.2 be modified to remove “power system Elements to be isolated, contingencies evaluated” as a minimum requirement. Having entities share their evaluation methods with other Entities appears to be unnecessary administrative work. Considering that it is the responsibility of the individual entity to perform their studies correctly, another entity should not have to worry about, nor does it have the responsibility for keeping tabs on, whether an external study was done to a single or double contingency level, what external Facilities become isolated, etc. Additionally, the NSRF is concerned with the phrase “Fault current used” as it applies to R1, Part 1.2. In consideration that Fault current values do not necessarily mean that two entities are using

Organization	Yes or No	Question 3 Comment
		like models, recommend a comparison of boundary equivalents be used instead to ensure that the models are comparable between entities. If not, entities would potentially be sharing every value for every iteration to ensure like models. Suggested revisions to R1, Part 1.2 in support of the above comments are as follows: 1.2. Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with Interconnected Element(s) that include two or more Registered Entities, a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, proposed revisions to the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, boundary equivalents at necessary buses Fault currents used, any issues identified, and any additional revisions proposed). If existing documentation does not include enough detail to meet the requirement for an acceptable Protection System Study, utilities will be forced to add to the existing documentation for compliance purposes even though the existing settings coordination is adequate. This will place additional compliance burden on utilities while not necessarily improving reliability. Since there is no evidence of widespread mis-coordination of Protection Systems associated with Interconnection Elements, it would seem reasonable to have this standard apply to any changes made to an existing Protection System or all new Protection Systems.

Response: Thank you for your comment.

1. **In response to stakeholder comments, the drafting team has refined the examples given in Requirement R1, Part 1.2 of the minimum information required in a summary of the results of a Protection System Coordination Study (PSCS).**
2. **The drafting team believes, even for functional entities under the umbrella of a single company, there is a reliability benefit associated with the provision for the information required in a summary of results of a PSCS from Transmission Owner to**

Organization	Yes or No	Question 3 Comment
Generator Owner. The drafting team does acknowledge that in the cases where a single person is doing the overall coordination for a given interconnection; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study should be sufficient for use by both owners. **3. In response to stakeholder comments, the drafting team has refined the examples given in Requirement R1, Part 1.2 of the minimum information required in a summary of the results of a Protection System Coordination Study. The particular items you mentioned were removed from the requirement.**		
American Transmssion Company, LLC	No	The drafting team states that there is no evidence of wide spread misoperation due to lack of coordination. However, R1 requires a utility to establish an evidence package of legacy coordination that predates PRC-001's effective date. While 48 months is an improvement to PRC-027, that timeframe still imposes a significant burden on utilities, especially those that are not vertically integrated. ATC recommends that the drafting team consider changing the implementation period for R1 from 48 months to 72 months.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Essential Power, LLC	No	The time frame is not the issue. R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.
Response: Thank you for your comment. **The drafting team believes that the Generator Owner is an appropriate Applicable Entity for this Standard since they often apply Protection Systems that require coordination with other owners' Protection Systems.**		
Cogentrix Energy Power Management, LLC	No	The time frame is not the issue. R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. **The drafting team believes that the Generator Owner is an appropriate Applicable Entity for this Standard since they often apply Protection Systems that require coordination with other owners' Protection Systems.**		
Nebraska Public Power District	No	To mitigate compliance risks for various types of data formats for existing studies and studies older than June 2007 this standard will likely require utilities to go back and update all data so that it meets the requirements and description of evidence in the application guidelines when the requirements become enforceable. This could likely take longer than 3 years. I would recommend more time such as 6 years based on two audit periods (time depends on the number of applicable system ties as well).
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Southwest Power Pool Reliability Standards Development Team	No	We are concerned that 48 months could still not be sufficient for these studies. We would ask that the team consider 72 months. There is a concern that with all the companies having new standards to comply with, the Transmission Owners/Generation Owners are being overloaded and have the same resources.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Tennessee Valley Authority	No	We do not feel like 48 months is a reasonable timeframe to meet the minimum requirements for Protection System Studies (PSS). In the current form of the standard, for an existing PSS to be valid, several minimum requirements are given in R1.2. While this is a good requirement for new PSS, it eliminates almost all of our existing PSS as being valid. We have the stance that many of our

Organization	Yes or No	Question 3 Comment
		existing PSS are of a high quality and should be considered valid, but do not meet the minimum requirements from R1.2. We recommend allowing existing PSS to be submitted in their current form between all protection system owners of an Interconnected Element within a reasonable time frame of the standard effective date and allowing the owners to approve the existing PSS as valid if they desire. Then, that existing PSS could be used as the baseline PSS until the 10% change in fault occurs from the existing dated PSS. At that time, a new PSS should be performed to meet the minimum requirements as outlined in R1.2.
Response: Thank you for your comment. **The drafting team recognizes that entities approach the process of protection system coordination according to individual entity policy and procedure, yet still achieve the same high quality results in the end. Based on your and others' comments, the drafting team has modified the timeframe associated with Requirement R1, Part 1.1.1 to 60 calendar months and revised the minimum information required in a summary of the results of a Protection System Coordination Study. The drafting team believes that a previous study can be used as a basis of a summary that includes all the needed information and send it to the other party to review after the effective date of the standard.**		
Wisconsin Electric Power Company	No	1.We strongly believe that 60 months would be a more achievable time frame to study the many interconnections that an entity may have. This will also allow Generator Owners the time needed to gain the resources required to perform these studies, since they may not be presently so equipped. As stated by the drafting team in the rationale for R1 there is no evidence of wide spread mis-coordination of Protection Systems associated with Interconnected Elements. 2.It would also be helpful to provide a better description of what is required to be included in a Protection System Study. For example, is the study required to include pilot scheme timing and element coordination, breaker failure coordination, coordination under minimum and maximum fault current cases, etc?
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
1. Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months. 2. A Protection System Coordination Study (PSCS), by definition within PRC-027, must demonstrate that existing or proposed Protection Systems operate in the desired sequence for clearing Faults. Most entities have internal procedures regarding the performance of coordination studies that produce the results required, but may not involve the exact same process or procedures that another entity follows to achieve Protection System coordination. The drafting team chose not to specifically dictate the elements of this process, but rather to continue to allow entities to "demonstrate that existing or proposed Protection Systems operate in the desired sequence for clearing Faults" according to their own internal procedures. The examples of information required in a "summary" of the results of a PSCS represent a minimum set of data that must be provided so the receiving entity can effectively assess coordination of the system. The drafting team has revised the examples to add clarity and the particular example provided in your comment has been removed.		
Ameren	Yes	Note- No. 1 objection is above in Question 1 (2) Requirement R2 requires short circuit study every 24 months even though the drafting team's own rationale is that other requirements will trigger Protection System Studies first. Thus we believe that R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. (3) VSL escalation in 10 days is not representative of the severity of the violation. The drafting team correctly points out in R1 rationale that it "has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements." We have about 500 Interconnected Elements per our present understanding of Draft 2 definitions and guidance. We recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity's Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively. Specifically, Lower would apply to up to

Organization	Yes or No	Question 3 Comment
		5% so that even a single Interconnected Element would be a violation.
Response: Thank you for your comment. 1. **The drafting team revised Requirement R2 to require, at least once every 60 calendar months, Transmission Owners perform a short circuit study and calculation of Fault current deviation for its Interconnected Elements or provide a technical justification why periodic fault current studies are not necessary for the coordination of Protection Systems associated with Interconnected Elements.** 2. **Some of the VSL increments have been increased but the drafting team believes the 10-day increments are appropriate in some cases. The use of percentages in the VSLs for this standard is not permitted because the requirements in the standard are specific to each Interconnected Element.**		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with question 3, we have the following general comments: (1) R2, 2.1.1 - Reference to the Protection System Study should be the most recent Protection System Study to be consistent with the rest of the requirement and the use of the word 'available' is a little problematic. What if no study exists? As we read it, the requirement to do a study is within 48 months of the effective date of the standard, while the requirement to do a short circuit study is at least every 24 months. If the Protection System Study is not available, is there no requirement to do the short circuit study? (2) R2, 2.2 - For clarity, we suggest rewording the first sentence to read 'Within 30 calendar days after identification, through the calculation performed pursuant to Requirement R2, Part 2.1.2, of a deviation in...' (3) R3, 3.1 - No time frame is given and it is unclear as to whether these details are to be only for proposed or future changes or additions, or whether it can be 'notice after the fact' (when read with the remaining requirements, it would be assumed it is 'prior notice', but that's not clear on the face of this part 3.1). In addition, should 'facilities' be capitalized in 3.1? Also, there needs to be consistent references to 'changes and additions' or just 'changes' within this R3

Organization	Yes or No	Question 3 Comment
		as currently there are references to both made. (4) R3, 3.2 - We suggest moving the time frame to the start of the Part for consistency with the drafting of other Parts and for ease of reading. (5) R3, 3.3 - We believe that the timeline is incomplete. Assuming that the timeline is meant to be 'within 30 calendar days of the (proposed?) changes or additions being made'. (6) VSLs/VRF table: R1, R3 - For consistency, the references should read 'less than or equal to 10 calendar days' instead of '10 calendar days or less'. (7) VSLs/VRF table: R4 - All of the references to 4.1 appear to be incorrect because 4.1, as currently drafted, does not require confirmation of acceptance of the summary results.
Response: Thank you for your comment. 1. **If you do not have a Protection System Coordination Study, you cannot perform a Fault current comparison.** 2. **The drafting team considered this alternate language; however, we believe the existing language is sufficient.** 3. **The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The drafting team capitalized "Facilities" but believes the other language is appropriate as written.** 4. **The drafting team believes the overall language of the requirement is appropriate as written.** 5. **The changes noted in Requirement R3, Part 3.3 are not proposed changes, they are indentified as 'changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components'.** 6. **The drafting team made the suggested changes for consistency in the VSL language.** 7. **The VSLs have been modified for consistency with the Requirement 4, Part 4.1 language.**		
Operational Compliance	Yes	It would be great if NERC provided a common format for all of us to use when providing this information
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
Acceptable evidence (per Measure M1) is a Protection System Coordination Study (PSCS) or a summary of the results of the PSCS. **The examples of information required in a "summary" of the results of a PSCS represent a minimum set of data that must be provided so the receiving entity can effectively assess coordination of the system. The drafting team has revised the examples to add clarity.**		
JEA	Yes	There is no place to put in a comment for R2 so this is for R2. We believe that the requirement to perform an analysis should be changed from once every 24 months to once every 36 months. Whenever changes are done to the system an analysis is done so this for areas that have not changed and we believe that once every 3 years should be sufficient.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team extended the 24 month review of Fault currents to 60 calendar months.**		
Imperial Irrigation District (IID)	Yes	
GP Strategies	Yes	
Dominion	Yes	
SERC Protection and Controls Subcommittee (PCS	Yes	
seattle city light	Yes	
Certain Members of the ISO RTO Council	Yes	
Duke Energy	Yes	
US Bureau of Reclamation	Yes	

Organization	Yes or No	Question 3 Comment
pacificorp	Yes	
Texas Reliablity Entity	Yes	
Tacoma Power	Yes	
City of Austin dba Austin Energy	Yes	
Independent Electricity System Operator	Yes	
Idaho Power Co.	Yes	
Exelon Corporation and its affiliates	Yes	
Xcel Energy	Yes	
City of Tallahassee	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.

Response: Thank you for your support.

The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and

Organization	Yes or No	Question 3 Comment
communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise some of the VSLs.		

4. **In Requirement R4, the drafting team replaced the need to 'reach agreement' with 'confirming acceptance.' Do you agree with this change? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

The majority of the commenters agreed with the change from 'reach agreement' to 'confirming acceptance'.

Several commenters felt the change made the requirement more ambiguous and were unclear what 'confirming acceptance' means. The confirming acceptance indicates that the entity has not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agree with the other entities philosophy. The drafting team modified Requirement 4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.

A few commenters felt Requirement R4, Part 4.2 was unnecessary and should be eliminated. The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.

A few commenters felt the standard should include a conflict resolution process for situations when 'acceptance' cannot be reached. The drafting team believes that any conflict resolution should be handled through normal business practices.

Organization	Yes or No	Question 4 Comment
Manitoba Hydro	No	(1) R4, 4.2 - The concept of 'accept' the changes are problematic. We are unclear as to what exactly this means? Is it something more than acknowledging that the changes are occurring? Does it go so far as 'agreement' with the changes? What happens if the owner does not 'accept' the changes? (2) R4, 4.1 - For consistency with wording the in R3, 'planned change' should be 'proposed change' or 'addition'.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. 1. **Based on stakeholder comments, the drafting team modified Requirement 4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.** 2. **The suggested change has been made.**		
Georgia Transmission Corporation	No	1) The protection criteria and philosophies between entities can differ. For example, one entity may use the practice of coordinating for normal and single worst case contingency conditions, which is included in information/documentation provided to the neighboring entity in such Protection System Studies. The neighboring entity may have a slightly different protection criteria or philosophy, so exceptions may be required on a case by case basis using the "art and science" of protective relaying. Therefore, interpretation of 'confirming acceptance' means there may be differences in protection elements used by each entity but that there were no major disagreements and that generally the methods were acceptable and included using industry protection practices. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance.
Response: Thank you for your comment. 1. **The drafting team acknowledges that entities may have differing protection philosophies. The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the**		

Organization	Yes or No	Question 4 Comment
affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues. 2. The drafting team believes that any conflict resolution should be handled through normal business practices.		
Bonneville Power Administration	No	According to this standard, something as simple as changing a CT ratio must now be communicated to all interconnected functional entities and documented. The interconnected functional entities must then “confirm acceptance” of the CT ratio change before the change can be made. The acceptance must then also be documented. This level of bureaucracy is unnecessary and counterproductive. The change from “reach agreement” to “confirming acceptance” is irrelevant.
Response: Thank you for your comment. **Yes, current transformer ratios are listed as one of the changes listed in Requirement R3, Part 3.1 that must be communicated. The drafting team does not understand any circumstance where a current transformer ratio in a Protection System would be changed that would not result in a change to the Protection System settings.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
FirstEnergy	No	FirstEnergy proposes that R4 Part 4.2 be deleted. The requirement is overly burdensome and R4 part 4.1 should provide sufficient evidence of whether or not the entity receiving study results believed any further action was required. Absent any such notification, the party would by default be accepting of the information. In regard to need for "acceptance" prior to planned changes FirstEnergy does not believe this is necessary. The drafting team in its rationale provided for Requirement R1 indicated "The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements" therefore we do not believe R4 part 4.2 is a necessary reliability requirement. Furthermore, other changes (R3 part 3.3) potentially

Organization	Yes or No	Question 4 Comment
		trigger upgraded Protection System Studies being communicated without “acceptance” prior to their implementation.
Response: Thank you for your comment. **The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Nebraska Public Power District	No	Getting acceptance within the required time frame is not in the control of the requestor. The concern is the numerous timelines in this standard that require timely responses will create an overly complex standard that will be difficult implement and to audit. The starting points for the timelines will be difficult to audit as well since much of this must be determined between two or more entities. How will enforcement view a requesting utility that sends a timely request but the response is a late confirmation of acceptance? The numerous time lines will create significant confusion and very complex data retention practices that will be difficult to track and difficult to audit. It appears the focus is more on time lines and the likely result is the content of the shared information will likely suffer due to the burden of tracking dated communications between entities. This draft standard includes time lines ranging from “prior to in service date, 30 days, 90 days, 6 months, 2 years and 4 years”. There should be fewer and simpler time lines with the focus on if the sharing of information took place and not on when did it take place. The SDT statement below should be generalized to the standard as a whole:”The SDT believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the SDT sees the entity initiating any change as having the incentive to move the process along in

Organization	Yes or No	Question 4 Comment
		a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date,"At a minimum remove the calendar day references and make them all 6 months for simplicity so the option is to use and agreed upon time or 6 months. Possible Suggestions: A simpler method would be after the initial 4 years to perform a study then every 24 months perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the interconnecting bus per Requirement R1 and demonstrate that the fault model was provided to the interconnecting entities within this time period along with the settings so the receiving entity can review against their design. Auditing would verify this data was sent on a two year schedule. For new protection interfaces verify protection studies or relay settings or summaries of studies were exchanged for review prior to the equipment going in service.
Response: Thank you for your comment. **The drafting team believes the timeframes in the standard, as revised, are necessary and appropriate.**		
Ingleside Cogeneration LP	No	Ingleside Cogeneration still holds to the position that a dispute resolution process needs to be defined should we reach an impasse with the TO. R4 still requires that both parties "accept" the proposed change - which means that one or the other could unreasonably demand an Protection System-related expenditure without any need to demonstrate that a corresponding reliability benefit will be realized. It is not apparent to us that this situation is already addressed in NERC's Rules of Procedure, which ultimately is the governing document for continent-wide Reliability Standards.
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal business practices.**		

Organization	Yes or No	Question 4 Comment
National Grid and Niagara Mohawk (A National Grid Company)	No	It is not clear where the old text "reach agreement" and the new text "confirming acceptance" were/are used. Also, "confirming acceptance" is vague in meaning.
Response: Thank you for your comment. **The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Midwest Reliability Organization NERC Standards Review Forum	No	R4, Part 4.2: In consideration that R4, Part 4.1 already requires entities to review the results of a Protection System Study and provide any related feedback, recommend Part 4.2 be removed from the standard. Without additional guidance within the standard specifying the timeframe in which an entity must provide its confirmation, the entity implementing the planned change could potentially be left waiting indefinitely for confirmation despite the study already being reviewed and accepted as part of Part 4.1. If part 4.2 is not removed, recommend that additional guidance be provided concerning time frames (90 days?).
Response: Thank you for your comment. **The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Xcel Energy	No	Requirement 4.2 requires entities to receive evidence confirming acceptance of changes prior to implementing these changes. This coordination already occurs,

Organization	Yes or No	Question 4 Comment
		and we believe this should be a standard practice for all applicable entities. However, we do not agree that this documentation-only requirement is necessary or beneficial to reliability. Instead, we believe this would deter valuable resources to unnecessary compliance evidence activities. Therefore, we recommend that this requirement be eliminated.
Response: Thank you for your comment. **The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Wisconsin Electric Power Company	No	The current draft standard lacks any clear responsibility for performing the complete Protection System Study, especially if the interconnected parties cannot accept or reach an agreement. The recommended change is to make the Transmission Owner accountable for the overall Protection System Study, at least at the Generator-Transmission interconnections. The other entities such as Generator Owners should be responsible to provide the necessary data required for the overall study. This makes the most sense based on limited resources and capabilities, as well as access to all data. This is especially true for independent Generator Owners that operate in the deregulated market. It is not feasible to make all entities somehow responsible for the study.
Response: Thank you for your comment. **The drafting team believes that the Generator Owner is an appropriate Applicable Entity for this standard since they often apply Protection Systems that require coordination with other owners' Protection Systems.**		
Southern Company	No	The parties at the opposite ends of an interconnecting facility may not have the same protection philosophies, and acceptance may not be achievable. It is

Organization	Yes or No	Question 4 Comment
		unclear what it means to confirm acceptance. Does this mean that the two must come to an agreement for each other's protection system settings, or is it acceptable to agree that we disagree?
Response: Thank you for your comment. **The drafting team acknowledges that entities may have differing protection philosophies.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
City of Tallahassee	No	These phrases do not appear to be contained within draft two.
Response: Thank you for your comment. **The drafting team intent was to indicate the thought behind the fact that language was changed in R4.2 to indicate 'confirm the owner(s) of each Facility associated with the affected Interconnected Element accept...'** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Northeast Power Coordinating Council	No	This change is more ambiguous than reach agreement. How can changes to Protection Systems occur unless agreement is reached via a signed off Protection System Study? What does it mean to confirm acceptance?
Response: Thank you for your comment. **The confirming acceptance indicated that the entity had not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agreed with the other entities philosophy.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications**		

Organization	Yes or No	Question 4 Comment
associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.		
Hydro One Networks Inc.	No	This change seems more ambigious than "reach agreement". How can changes to Protection Systems occur unless agreement is reached via a signed off Protection System Study? What does it mean to "confirm acceptance"?
Response: Thank you for your comment. **The confirming acceptance indicates that the entity has not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agree with the other entities philosophy.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Texas Reliablity Entity	No	TRE agrees with the need to notify the Facility Owner of the proposed changes. However, if the receiving entity does not agree with the proposed changes, there needs to be a venue to reach consensus. The receiving entity should be able to suggest changes based on technical rationale to resolve the disparities. A provision for dispute resolution needs to be provided. TRE suggests re-wording R4.2 to - "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, notify the Facility owner(s) associated with the affected Interconnected Element. If consensus cannot be reached on the proposed Protection System(s) changes, each entity shall document the technical rationale for its position on each disputed issue prior to implementation."
Response: Thank you for your comment.		

Organization	Yes or No	Question 4 Comment
The drafting team believes that any conflict resolution should be handled through normal business practices. **Note: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Pepco Holdings Inc & Affiliates	No	We find that changing the wording from "confirming acceptance" to "reaching agreement" does little to address the root problem associated with mandating mutual agreement. We suggest Requirement R4 be removed entirely or extensively re-written to address the concerns outlined below: Requirement R4 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What I f agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R4.2 until agreement is

Organization	Yes or No	Question 4 Comment
		reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? This is the problem with mandating that an agreement between two parties be reached. It is further compounded by requiring that an agreement be reached within a set timeframe. It is unreasonable and unfair to hold one party non-compliant due to the failure of another party to reach agreement. Furthermore, in the example provided above, it is a detriment to reliability to delay implementation of the setting change on breaker D just because mutual agreement could not be reached.It is important to ensure that information on new, or modified, Protection Systems are shared between parties, so that each party may assess the impact of the change and ensure their Protection Systems are properly set and coordinated. The emphasis should be on sharing of information (such as relay setting changes) and not the details of performing the "Protection System Study" and all the associated approval schedules. As such, it may be reasonable to have a Reliability Standard to ensure setting information has been exchanged (which was the original intent of the PRC-001-1 standard). But it should be left at that. Mandating mutual agreement with compliance implications, without providing a clear division of responsibilities and assignment of who will be held non-compliant if agreement cannot be reached is unfair to either party.

Response: Thank you for your comment.

The drafting team believes that any conflict resolution should be handled through normal business practices.

The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.

Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications

Organization	Yes or No	Question 4 Comment
associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.		
ACES Standards Collaborators	Yes	(1) We had no issues with the use of agreement in the previous version. Coordination of protection systems is important enough to obtain agreement. Furthermore, we believe confirming acceptance and reaching agreement are synonymous. If two entities need to "resolve differences and confirm acceptance that their Protection Systems are coordinated," that is the same as stating that the entities need to reach an agreement.
Response: Thank you for your comment and support. **The changes were made based on previous comments from those that believed agreement was too strong. They indicated that confirming acceptance indicates that the entity has not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agreed with the other entity's philosophy.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
SERC Protection and Controls Subcommittee (PCS	Yes	1) The protection criteria and philosophies between entities can differ. For example, one entity may use the practice of coordinating for normal and single worst case contingency conditions, which is included in information/documentation provided to the neighboring entity in such Protection System Studies. The neighboring entity may have a slightly different protection criteria or philosophy, so exceptions may be required on a case by case basis using the "art and science" of protective relaying. Therefore, interpretation of 'confirming acceptance' means there may be differences in protection elements used by each entity but that there were no major disagreements and that generally the methods were acceptable and included

Organization	Yes or No	Question 4 Comment
		using industry protection practices. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance.
Response: Thank you for your comment and support. **1. The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.** **2. The drafting team believes that any conflict resolution should be handled through normal business practices.**		
Dominion	Yes	1) Dominion interprets the wording "confirming acceptance" to mean that there are no major disagreements and that generally the methods between entities are acceptable using industry protection practices even if different protection setting philosophies' exists. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance. The initiating party should not be restricted from applying appropriate settings due to the lack of acceptance confirmation from the other entity.
Response: Thank you for your comment and support.		

Organization	Yes or No	Question 4 Comment
1. The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues. 2. The drafting team believes that any conflict resolution should be handled through normal business practices.		
ReliabilityFirst	Yes	ReliabilityFirst abstains and offers the following comments for consideration: 2. Requirement R4 Violation Severity Level a. During the previous comment period, ReliabilityFirst recommended that VRF for R4 be changed to "High" since this is dealing with interconnection protection systems. The SDT response by indicating they "...believes the VRF for Requirement R4 more aligns with the NERC criteria for a medium risk. " After reading the NERC criteria for a medium risk, ReliabilityFirst would agree only if the Time Horizon of this requirement is changed to "Long Term Planning"
Response: Thank you for your comment. The drafting team believes that the Time Horizon for Requirement R4 is assigned correctly at "Operations Planning" and also believes the VRF of "Medium" is correct. No changes were made.		
PPL Corporation NERC Registered Affiliates	Yes	There is no clear responsibility in the standard if both parties cannot confirm acceptance.
Response: Thank you for your comment and support. The drafting team believes that any conflict resolution should be handled through normal business practices.		
Independent Electricity System Operator	Yes	We agree with the intent of the proposed changes, but believe some editorial changes are necessary for more clarity. We suggest the following wording for the SDT's consideration: 1. "Confirm with the owner(s) of each Facility associated with the affected Interconnected Element that it accepts (or acceptance of) the resulting

Organization	Yes or No	Question 4 Comment
		Protection System(s) changes." 2. In fact, Part 4.1 could also be worded to add clarity:"Within 90 calendar days after receipt of the proposed Protection System(s) changes,"

Response: Thank you for your comment and support.

1. **Based on stakeholder comments, the drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**
2. **The "receipt" in Requirement R4, Part 4.1 is referencing the summary results of the Protection System Coordination Study. The drafting team believes this is clear and unambiguous and declines to make the suggested change.**

Organization	Yes or No	Question 4 Comment
Western Small Entity Comment Group	Yes	
Imperial Irrigation District (IID)	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
GP Strategies	Yes	
Luminant	Yes	
seattle city light	Yes	
Florida Municipal Power Agency	Yes	
Certain Members of the ISO RTO Council	Yes	

Organization	Yes or No	Question 4 Comment
Duke Energy	Yes	
JEA	Yes	
US Bureau of Reclamation	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	
pacificorp	Yes	
Western Electricity Coordinating Council	Yes	
Dynegy	Yes	
American Transmssion Company, LLC	Yes	
Essential Power, LLC	Yes	
American Electric Power	Yes	
Liberty Electric Power LLC	Yes	
Public Service Enterprise Group	Yes	
Ameren	Yes	
Tacoma Power	Yes	
Entergy Services, Inc. (Transmission)	Yes	

Organization	Yes or No	Question 4 Comment
City of Austin dba Austin Energy	Yes	
ITC	Yes	
Idaho Power Co.	Yes	
Sacramento Municipal Utility District	Yes	
Exelon Corporation and its affiliates	Yes	
Cogentrix Energy Power Management, LLC	Yes	
Kansas City Power & Light	Yes	
NV Energy	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.

Response: Thank you for your comment.

The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly

Organization	Yes or No	Question 4 Comment
based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise some of the VSLs.		

5. **The requirements and associated measures were modified to indicate that information was 'provided' instead of 'demonstrating that each affected entity received notification.' Do you agree with this change? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Some commenters identified that a few of the Measures did not synch up with the Requirements. The drafting team made the measures consistent with the Requirements. Some commenters noted that the format of the verbiage in several similar Measures was not consistent. The drafting team made the format consistent.

Several commenters asked about revisions to PRC-001. The drafting team noted several things related to this:

- The drafting team did not modify the purpose.
- The Applicability section was updated to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)
- The drafting team did add Measure M1, which reads: "For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel."
- The drafting team recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database..

A few commenters had questions about the 'agreed to time frames' provide in the standard. The drafting team noted that an agreed upon schedule is the schedule all involved parties agree to. In most cases, the drafting team believes the mutually agreed upon schedule would be of a longer time frame than the maximum days specified in the requirement; however, entities are free to agree to an earlier timeframe.

A few commenters wanted clarification on which Protection Systems were subject to the requirements of the standard. The drafting team stated that the relays to be considered are identified in the Facilities Section of the standard, which reads: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements." The conditions under which the Protection System Coordination Study is performed are dependent upon the owner's philosophies and practices. The drafting team recognizes that philosophies and practices may vary from owner to owner, and that is why it is important to share the results of studies with the other owners.

A few commenters pointed out that, in some cases, fault current variations do not impact coordination. The drafting team noted that Requirement R2 was revised to allow a technical justification demonstrating why Fault current does not affect the Protection System coordination.

A few commenters expressed concerns about entities needing to document that the other entity had received the notification. The drafting team noted that Requirement R4, Part 4.1 was modified as follows: Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Coordination Study (per Requirement R1, Part 1.2) and respond to the other owner(s): Accepting the results, or Rejecting the results, and suggesting modifications to resolve any identified coordination issues.

Several commenters noted the need for a conflict resolution process. The drafting team responded that any conflict resolution should be handled through normal business practices. Measure M9 (now M10) was modified as follows: Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that, prior to implementation of any proposed Protection System(s) changes, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted. The drafting team believes the requestor cannot be held accountable when the other party does not respond.

Several commenters requested changes in the flow chart and/or examples. The drafting team corrected errors in the flow chart and updated the examples and diagrams based on comments.

Several commenters had questions about the term “interconnected bus”. The drafting team noted that the diagrams were revised to clearly indicate the drafting team’s meaning of interconnected bus.

There were various grammatical suggestions for improvement in this section. The drafting team considered them all and made many of the suggested changes.

Organization	Yes or No	Question 5 Comment
ACES Standards Collaborators	No	(1) The measures do not match the requirements. For example, R4 requires entities to confirm acceptance, which would demonstrate that each affected entity received notification. Again, the drafting team is using synonyms that produce the same result as the prior draft. To show evidence that the

Organization	Yes or No	Question 5 Comment
		information was “provided” would have to be some sort of notification of receipt. (2) Does the drafting team intend further actions for coordination beyond providing the studies to applicable entities? (3) We recommend the drafting team develop an RSAW to better explain how compliance would be measured against this standard. Thank you for the opportunity to comment.
Response: Thank you for your comment. 1. **The drafting team intends that information is “provided” (synonymous with “sent”) and receipt of delivery is not required.** 2. **Yes, the drafting team intends for the receiving entity to review the Protection System(s) changes and identify any coordination issues.** 3. **The drafting team agrees with this approach and will work with NERC Compliance staff to develop an RSAW.**		
Independent Electricity System Operator	No	(1) We do not have a strong view one way or the other with respect to “provided” versus “demonstrating”. However, the wording used among Measures needs to be consistent. For example, in M1 the wording is “Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1. and 1.1.2, and 1.1.3 is a dated Protection System Study, or the summary results of...” seems reasonable since it shows the examples for “acceptable evidence”. The examples listed illustrate what constitute “acceptable evidence”. However, in M2, the wording “Acceptable evidence for Requirement R1, Part 1.2 demonstrating that the summary results of each Protection System Study (hard copy or electronic file formats) was provided....” Does not illustrate what constitutes “acceptable evidence”, thereby leaving that to interpretation. We suggest M2 (and M4) be reworded along the same line as that for the other Measures (M1, M3, M5 to M9). (2) The Comment Form does not have a question on “Do you have any other comments?” Therefore, we are submitting the following comment under this

Organization	Yes or No	Question 5 Comment
		Question. We reiterate our concerns previously expressed with respect to PRC-001:We do not agree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. If this is a training requirement, it should be transferred to the appropriate PER standards. c. Measures M1 is removed from the standard. This does not conform with the Elements of a Reliability Standard template, specifically those specified in the "Mandatory and Enforceable Sections of a Standard". d. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. However, leaving this not measurable and unnecessary requirement in PRC-001-3 is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT could have proposed a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee's advice/direction for appropriate actions. The SDT's response to our previous comment was "This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff." We do not believe that the staff has brought this to the Standards Committee's attention. Note that the Standards Committee is responsible for managing the

Organization	Yes or No	Question 5 Comment
		standards development process and as such, can make an informed decision to either request the SDT to expand its scope (via an amended SAR) to address the PRC-001 issue, or to ask staff or the SDT to prepare a separate SAR to address the issue in parallel. Leaving the PRC-001 hanging out there without a recourse is not a satisfactory solution, and may in fact harm reliability. Once again, we urge the SDT to take the initiative to bring this issue to the Standards Committee, with a proposal to amend the SAR or prepare a new SAR, or seek its advice and direction before continuing work on this project.
Response: Thank you for your comment. 1. **The drafting team modified the Measures to address your comment.** 2. **The drafting team made several modifications to PRC-001, including the addition of Measure M1, which reads: "For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel." The drafting team also recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.**		
seattle city light	No	Because there is no "other comments" section included in this comment form, the following comments about the timelines for specific actions are appended here. 1. (R3.2) "Data Requests . . . . 30 Days or agreed to schedule' Seattle requests that "agreed to schedule" be clarified, in particular the limits in determining this schedule. If no further clarity is added, Seattle suggests that "or agreed to schedule" simply be deleted. 2. (R2.1) Short Circuit Study . . . . . . 24 months SCL recommends that the time line of 24 months be removed and that the 10% change in fault current criteria serve as the replacement for this requirement. 3. (R4.1) "Review PS Study . . . . .90 Days or agreed upon schedule" Seattle is concerned that, depending upon the complexity of the study, a lot of back and

Organization	Yes or No	Question 5 Comment
		forth communication between the utility entities may be required. 4. Please clarify a. if each response to, or revision of the study trigger another 90 day review period and b. the limits as the defining an "agreed to schedule." If no further clarity is added regarding agreed to schedules, Seattle suggests that "or agreed to schedule" simply be deleted.

Response: Thank you for your comment.

1. **The drafting team intends that an agreed upon schedule is the schedule all involved parties agree to. In most cases, the drafting team believes the mutually agreed upon schedule would be of a longer time frame than the maximum days specified in the requirement; however, entities are free to agree to an earlier timeframe.**
2. **Since the 10% threshold cannot be determined unless the study has been done, the drafting team believes it is appropriate for there to be a requirement to do the study. Note: the time frame has been changed to 60 calendar months.**
3. **The 90 days or the agreed upon schedule only pertains to the initial review and response of the Protection System Coordination Study. The drafting team realizes that there could be a lot of back and forth after the initial review and response but there is no associated time frame.**

4a. Technically, your statement could be correct; however, the drafting team believes both parties will have an incentive to complete the process as soon as practical.

4b. The drafting team intends that an agreed upon schedule is the schedule all involved parties agree to. In most cases, the drafting team believes the mutually agreed upon schedule would be of a longer time frame than the maximum days specified in the requirement; however, entities are free to agree to an earlier timeframe.

Organization	Yes or No	Question 5 Comment
Bonneville Power Administration	No	1. BPA believes that the requirements and measures are onerous and should be eliminated. The change in wording is irrelevant. Additional Comments 2. R1.1 requires a protection system study to be performed, but does not explain what is required for a protection system study.R1.2 lists some minimum requirements of a protection system study, but leaves many unanswered

Organization	Yes or No	Question 5 Comment
		questions, for example: Which relays must be included in the study? Where are the faults to be applied? What contingencies should be applied for the study? How many buses back into the system must be reviewed? 3. R1.1.2 introduces the term “interconnecting bus” with no definition of what it is. 4. R2 is a requirement that pertains to each facility associated with an interconnected element. The use of the word “associated” is too vague and leaves the interpretation of this requirement wide open. 5. In R2, the need to perform a new protection system study is based on a 10% or greater increase in fault current. Since many relays are based on impedance or differential methods, the value of fault current has no bearing on their need for a coordination review. R2, therefore, results in an unnecessary and useless burden when applied to elements protected with these relays.

Response: Thank you for your comment.

1. **The drafting team believes the requirements and measures support the reliability intent of the standard.**
2. **The drafting team believes the relays to be considered are identified in the Facilities Section of the standard which reads: “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.” The conditions under which the PSCS is performed are dependent on the owner’s philosophies and practices. The drafting team recognizes that philosophies and practices vary depending on the owner and that is why it is important to share the results with the other owners.**
3. **Based on your comment, the drafting team has designated the interconnecting bus in the example figures to provide clarity.**
4. **The drafting team believes the word “associated” in the context used is clear.**
5. **The drafting team revised Requirement R2 to allow a technical justification explaining why Fault current does not affect the Protection System coordination.**

Organization	Yes or No	Question 5 Comment
Florida Municipal Power Agency	No	First, there should be an "any other comments" question. Seeing that there isn't one, we are adding our other comments here. 1. R3 - There should be thresholds of change to the bullets. For instance, changing the no-load tap changer of a GSU does minimally change the impedance of the GSU). transmission line neighbor installing a long chain link fence along the ROW will have a minimal impact on mutual coupling. These minimal changes do not require redoing the study, so, what percentage change in impedance requires redoing the study?
Response: Thank you for your comment. **The drafting team believes that information about any change (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the Interconnected Element.**		
Imperial Irrigation District (IID)	No	IID believes the affected entity need to demonstrate it received notification.
Response: Thank you for your comment. **Based on yours and others comments, R 4.1 has been modified as follows: Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Coordination Study (per Requirement R1, Part 1.2) and respond to the other owner(s): Accepting the results, or Rejecting the results, and suggesting modifications to resolve any coordination issues.**		
Nebraska Public Power District	No	Measurement 9 for R4 requires confirmation of acceptance prior to implementation of any planned protection system changes. This appears to be similar to 'demonstrating that each affected entity received notification.' The concern is holding one company responsible for actions of another that is not under the requestor's control. It is recommended that there be clarification that if the requestor does not get confirmation of acceptance in the proper time line

Organization	Yes or No	Question 5 Comment
		then the requestor is not accountable or subject to violations. Another option is to remove R4.2.
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal business practices. The old Measure M9 (new Measure M10) has been modified as follows: Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that, prior to implementation of any proposed Protection System(s) changes, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted. The drafting team believes the requestor cannot be held accountable when the other party does not respond.**		
CenterPoint Energy	No	Providing schedule information and project details by a transmission service provider to a generation entity may be governed by established, regional market rules that provide for what information can be shared with competitive entities. There are many installations in the ERCOT System where the owner of the interconnecting switchyard is not the same entity as the owner of the interconnected generation facility.
Response: Thank you for your comment. **The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the Generator Owner to ensure proper coordination of the Protection Systems covered by this proposed standard.**		
Salt River Project	No	Receipt of confirmation should be required to confirm coordination.
Response: Thank you for your comment. **The old Measure M9 (new Measure M10) has been modified as follows: Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that, prior to implementation of any proposed Protection System(s) changes, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted.**		

Organization	Yes or No	Question 5 Comment
NextEra Energy	No	See page 19 of the redline PRC-027 Guidelines and Technical Basis. " System condition used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions."Please clarify that "single contingency conditions" refers to breaker failure or protective system failure. It is not intended to mean single contingency operating conditions such as line or transformers out of service.
Response: Thank you for your comment. **The use of 'single contingency conditions' in this context is to indicate facility outages. e.g. line out.**		
Xcel Energy	No	Since the SDT did not provide a question for "any other comments", Xcel is using this question for that purpose. 1) We would appreciate some additional clarity as to what transmission fault conditions need to be evaluated by the Generator Owner. Figure 2 does not apply to very many of our units (on most, Breaker A would not exist and Breaker C is part of a breaker-and-a-half scheme). Is the generator supposed to evaluate only faults on the line between the GSU Transformer and the substation or evaluate his protection settings for a fault on any of the transmission lines leaving the substation? 2) Can the drafting team, either as part of the Application Guideline or in a separate document provide a list of protective functions the Generator Owner needs to evaluate or is it the complete suite of protective functions defined in the NERC SPCS Generator - Transmission Protection Coordination Guideline? 3) Requirement 3.1 is onerous as it requires notification for an open ended "when the proposed change modifies the conditions used in the coordination of Protection Systems." The requirement should be limited and instead provide a simple list of element changes that generally affect coordination with adjacent

Organization	Yes or No	Question 5 Comment
		Elements. 4) Similarly for 3.3, we recommend that this be modified to limit the scope to only changes that result in a change of performance or ratings. For example, settings that change the alarm conditions for a device or a “like-for-like” replacement should not be required to be communicated. Communicating every change would not improve reliability and would instead deter valuable resources to unnecessary compliance evidence activities.
Response: Thank you for your comment. 1. In the situation cited, the Transmission Owner would review the data to ensure there are no coordination issues with the settings provided by the Generator Owner. Conversely, the Generator Owner would be responsible to ensure the settings provided by the Transmission Owner for breaker B does not result in coordination issues with generation Protection Systems. Example: that a Transmission Owner back-up relay does not operate before a Protection System designed to isolate a station service bus. 2. The drafting team has decided not to reference the subject document; however, the drafting team recognizes that it would be a good reference. 3. The drafting team believes that the bulleted items in Requirement 3, Part 3.1 provide the ‘list’ suggested. 4. The drafting team believes that although these circumstances will be rare, the noted information should be shared with the other entity so that they can update their records and provide any needed feedback.		
City of Austin dba Austin Energy	Yes	(1) Austin Energy (AE) notes an inconsistency in R1.1.3 and the flowchart on page 22 of the clean version of Draft #2. R1.1.3 states that a Protection System Study is required “according to an agreed upon time frame” whereas the flowchart on page 22 says “perform the PSS within 6 months.” AE asks the SDT to update the flowchart to match the requirement language. (2) AE believes the VSLs for R4 are not consistent with the language of the standard, specifically R4.1 and R4.2. For example, the Severe VSL language should read “The responsible entity reviewed the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and responded as to whether further action is required, all per R4, Part 4.1, but was

Organization	Yes or No	Question 5 Comment
		late by more than 30 calendar days. OR The responsible entity failed to review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required, all per R4, Part 4.1. OR The responsible entity failed to confirm acceptance of any resulting Protection System(s) changes prior to implementing any planned change(s) associated with Requirement R3, Part 3.1 per R4, Part 4.2." AE is concerned about the current VSL language because it indicates the need to confirm acceptance of planned changes (e.g., new installation) instead of the resulting Protection System(s) changes.
Response: Thank you for your comment. **1. Based on your comment, the flowchart has been revised.** **2. The VSLs have been revised to match the revised requirements.**		
Dominion	Yes	1). Please replace "detect Faults on the BES Transmission System" with "protect the BES Transmission System" in all three places it appears in Figure 3. This proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 2). Dominion respectfully disagrees with the SDT feedback comment on Draft 1 where it was recommended to remove references from one Requirement to another Requirement. Dominion was not challenging consistency with the recommendation but were stating the need to simplify the wording in the standard. Each Requirement can stand on its own without the additional Requirement reference. By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement due to the fact that that it causes you to read between Requirements. Isn't this the purpose of the Process chart in the guidelines? 3). Under R1 - MI measure wording does not read as a completed statement.

Organization	Yes or No	Question 5 Comment
		Dominion suggests removing ‘that’ from the first sentence to “....demonstrating time frames”. 4). Dominion respectfully disagrees with the SDT feedback that in R2 the term “deviation” is synonymous with “change”. Deviation refers to variation from a standard, norm or mean. This is not a statistical calculation but a simple measure of change 5). In R3- 3.2, there appears to be a formatting issue. Any Requirement that references a calendar day is worded where the Calendar date is at the beginning of the statement; for example R3- 3.3. Need to change wording in R3- 3.2 for consistency throughout document to read “Within 30 calendar days of receiving a request or according to an agreed upon schedule, requested information related to coordination....”). 6) In Draft #1 Dominion wrote: “Throughout this Draft 1 of the standard, there are references that illustrate documentation requirements that are inconsistent. Recommend all be written as “(hard copy or electronic file formats)”. The SDT responded saying “Each measurement in the standard (M1 through M10) has as evidence the statement “dated documentation (hardcopy or electronic file formats).” This is not the case; the point was that M1 reads “either in hardcopy or electronic file formats”. This is minor but needs to be changed for consistency.

Response: Thank you for your comment.

1. **The drafting team used the term ‘detect Faults on the BES Transmission System’ to indicate those Protection Systems that may require review with other owners Protection Systems. The drafting team revised the phrase to read “installed for the purpose of detecting Faults on BES Elements” for consistency with the Facilities section of the Applicability. It is also noted that the identified interpretation was for the term ‘transmission Protection Systems’ which is not used in this Standard. Figure 3 has been modified to provide consistent language.**
2. **The drafting team still believes the references to other requirements in the standard are the best way to both maintain consistency and to describe the requirements. This approach has been approved through the Quality Review process and is**

Organization	Yes or No	Question 5 Comment
used in other NERC Reliability Standards. **3. Measure M1 was revised based on your comment.** **4. The drafting team made the suggested change.** **5. The drafting team believes Requirement R3, Part 3.2 is appropriate as written.** **6. The drafting team made the suggested change.**		
Western Small Entity Comment Group	Yes	The comment group has no comments regarding this question. This form provides no general comment area, so we are providing our additional comments here. We referenced the WECC Position Paper in the last round of comments, but now see that WECC did not submit comments. We urge the SDT to take a look at the paper. We received our copy from steve@wecc.biz . We can also forward a copy if an email address is provided. For the team's convenience, here is the relevant text: "WECC staff and WECC subject matter experts have reviewed the proposed standard and agree with the purpose of the standard. WECC staff and WECC subject matter experts agree that Protection Systems must be coordinated. However some subject matter experts believe that the proposed standard requires more documentation than is necessary and that the requirement to provide a hard copy or an electronic copy of each Protection System Study is administratively burdensome and not reflective of the intent of Results Based Standards. These subject matter experts believe that evidence that studies are coordinated and that entities have agreed to the results of System Protections Studies is adequate." We see that the SDT responded to Salt River Project's and other's similar concerns regarding hard copies by stating that that only summaries are needed, but we still see the standard as overly burdensome compared with the possible benefit. Tennessee Valley Authority, Dominion Power, Southwest Power Pool, the Nebraska Public Power District, Dairyland Power Cooperative, the Bonneville Power Administration, and the SERC Protection and Control Subcommittee provided some specific suggestions to reduce documentation burden which were all rejected. We urge the SDT to review these recommendations again.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **The drafting team believes the requirements in the standard accomplish the reliability objective of this standard and are not overly burdensome.**		
Duke Energy	Yes	Additional comment: R2.1.1 refers to "maximum available Fault current values", but it's unclear from the requirement or the Guidelines and Technical Basis how "maximum" is defined. We believe it should be maximum generation and all Facilities in service.
Response: Thank you for your comment. **The drafting team has included in the Guidelines and Technical Basis section the following which it believes answers this question: 'These studies are typically performed assuming maximum generation and all Facilities in service.'**		
Tacoma Power	Yes	Additional Comments: 1. Why is there a version 4 for PRC-001 (under Version History) when the standard being balloted is version 3 (PRC-001-3). 2. PRC-027-1 does not appear to impose any requirements as to how quickly issues identified in a Protection System Study are addressed. It may be difficult to impose such a timeframe since some issues may just require a relay setting change, while others may require more drastic scheme modification, including design, procurement, installation, and commissioning. Perhaps requirements could be added to develop, within a specified timeframe, and then implement a mutually agreeable Corrective Action Plan. As written, it appears that an entity can be compliant with Protection System Studies that always indicate existing coordination issues, which does not completely achieve the purpose of the standard. Without a mechanism to close the loop, PRC-027-1 appears to require a lot of documentation and coordination without any guarantee that

Organization	Yes or No	Question 5 Comment
		existing coordination issues will ultimately be resolved. R4.1 really only requires entities to come to terms on the Protection System Study, but does not explicitly require any other course of action on existing coordination issues. 3. In M1, the sentence ending in "...demonstrating that the time frames specified in Parts 1.1.1 and 1.1.2" in a fragmented sentence. Also, should this sentence have "and 1.1.3" at the end? 4. M2 is a fragmented sentence. 5. M4 is a fragmented sentence. 6. As written, it may be difficult to audit parts of R3.1. Some of the language seems to be subjective and implicitly left to engineering judgment. a) First, it is not completely clear what the drafting team intended by the wording "associated with" or how an auditor might interpret that wording. b) Second, please consider changing "...or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s)" to "...or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s), as stipulated in the existing Protection System Study." This should make it easier to audit this aspect of R3.1. c) Third, regarding the second through fourth bullets, engineering judgment will be required to determine when impedances need to be changed. For example, minor modifications could be made to a transmission line that, in a purely academic sense, could change the impedance; however, an entity may opt not to update the impedance based upon engineering judgment that the change is not significant to the impedance model. 7. For emphasis, under R3.2, considering changing "...within 30 calendar days of receiving a request or according to an agreed-upon schedule" to "...within 30

Organization	Yes or No	Question 5 Comment
		calendar days of receiving a request or according to an agreed-upon schedule, which may be longer or shorter than 30 calendar days." 8. R4.2 does not seem to explicitly require that a Protection System Study be completed before implementing changes indicated in R3.1, only that the changes are accepted. 9. R1.1.3 seems to suggest that the Protection System Study must be completed prior to implementation. However, according to the flow chart, it appears that a Protection System Study could be produced (in theory) six months after the changes were made. Furthermore, the flow chart applies the six-month timeframe even to R1.1.3, which does not match the text in R1.1.3.

Response: Thank you for your comment.

1. **Thank you for pointing out this mistake. The drafting team made the correction.**
2. **The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements. Requirement R4, Part 4.1 requires entities to 'respond as to whether any coordination issues were identified through a review of the summary results of a Protection System Coordination Study and if any further action is required'. The drafting team believes any coordination issues discovered through the periodic review will ultimately be resolved by the Protection System owners at the Interconnected Element.**
3. **The drafting team made the correction.**
4. **The drafting team made the correction.**
5. **The drafting team made the correction.**

6a. The drafting team made a change to the Guidelines and Technical Basis for Requirement R3 to clarify what is meant by the term 'associated with'. It now reads: "The drafting team recognizes that Facility changes at other locations can impact the Protection System Coordination Study of the Facility associated with the Interconnected Element; e.g., the addition of a large autotransformer bank or generator not directly connected to the Interconnected Element."

6b. The drafting team believes the existing wording is sufficient and declines to make the suggested change.

6c. The drafting team added the following language to the Rationale box for Requirement R3: "The drafting team believes that information about any change (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the Interconnected Element." The language

Organization	Yes or No	Question 5 Comment
contained in the Rationale box will remain as part of the standard. 7. The drafting team believes the existing wording is sufficient and declines to make the suggested change. If the time frame is shorter than the minimum 30 days, there would be no need to be 'agreed upon'. 8. Requirement R1, Part 1.1.3 requires that a Protection System Coordination Study be performed "according to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 or Part 3.3". Requirement R4, Part 4.2 requires confirmation that other owners of each Facility associated with the affected Interconnected Element have completed a review of the Protection System changes and any identified coordination issues were resolved prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1. 9. The drafting team revised the flowchart to indicate that a study must be performed before any changes are made. The flowchart was also modified to reflect that the 6 month timeframe is not associated with Requirement R1, Part 1.1.3.		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with question 5, we have the following general comments: (1) M1 - The word 'that' in the third line should be deleted and we believe that the words 'is dated documentation' are missing after 'Acceptable evidence for Requirement R1, 1.2. (2) M3 - For consistency, the word 'formula' should be replaced with calculation in Requirement R2, 2.1.2. (3) M4 - For clarity and consistency with the other Measures, we suggest rewording the opening sentence to read 'Acceptable evidence for Requirement R2, Part 2.2 is dated documentation (hard copy or electronic file formats) demonstrating that the updated Fault current values were provided within....'. (4) M5 - The wording of this section does not match the wording of the requirement. The words 'in hard copy or electronic file formats' should follow the word summary, not after the word settings.
Response: Thank you for your comment. 1. The drafting team made the suggested changes in Measures M1 and M2. 2. Measure M4 (old Measure M3) has been modified to include the following: determined by the equation.		

Organization	Yes or No	Question 5 Comment
3. The drafting team made the suggested change. **4. The drafting team made the suggested change.**		
Sacramento Municipal Utility District	Yes	Although this is unrelated to Question 5 there was no other space allocated for the for “any other comments.” While this is most likely a clerical error, we feel it is not appropriate to post a standard without making such a question available.
Response: Thank you for your comment. **The standards development process does not require a ‘catch-all’ question be included in every posting of a draft standard. The drafting team asked specific questions in order to gather specific answers to those questions.**		
American Electric Power	Yes	Because the comment form provides no section to provide “general comments”, AEP offers them below. AEP would like to inform the drafting team that our negative vote on this standard is primarily driven by A) the lack of clarify in regards to its scope (as discussed in the response to Q2) and B) the timeframe allotted to perform the Protection System Study (as discussed in the response to Q3). C) It would be more appropriate for R 1.1.1 to be included in the implementation plan, rather than embedded within the standard itself. D) The proposed standard is difficult to follow, in the way that it jumps back and forth among requirements. We would encourage any changes which might increase the readability of the proposed standard.
Response: Thank you for your comment. **A) The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System**		

Organization	Yes or No	Question 5 Comment
components need to be coordinated between entities. B) Based on stakeholder comments, the drafting team revised the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months. C) The drafting team agrees your suggestion provides one way of addressing the requirements to have documented Protections System Coordination Studies for each Interconnected Element. However, the drafting team believes the structure of Requirement R1, Part 1.1.1, as currently written, achieves this goal. Further, NERC performs periodic review of standards and the requirement can be removed at that time, if appropriate. D) The drafting team believes the revised 'draft 3' of the standard is more readable.		
ITC	Yes	1. Figures 1-5 designate a preferred responsibility of coordination on either entity which contradicts with intent of R3. R3 details all the changes which must be provided to the adjacent utility, seemingly so they can coordinate their protection over yours. However, Figures 1-5 place the coordination responsibility on the utility which does not own the Protection System. I agree that R3 should remain almost as-is. However, the coordination responsibilities in Figures 1-5 should be reversed or preferably removed. Owner R should be responsible for coordinating Breaker A relays. Only the owner should be responsible for coordinating this relay. 2. SDT needs to define the term "interconnecting bus" and perhaps identify the interconnecting bus in Figures 1-5. 3. In Figures 1-4 the Interconnected Element is a line.
Response: Thank you for your comment. 1. The Figures and associated processes are examples of options that may be used to achieve coordination and are not intended to be all inclusive. The drafting team believes the owner proposing changes in Figure 5, e.g. Transmission Owner S, would not necessarily have the Protection System information and setting to ensure that coordination will be achieved; therefore, the procedures noted for Figure 5 ensure that Transmission Owner R and Generator Owner T can verify that changes made by Transmission Owner S can be coordinated. The drafting team believes the Figures do not contradict the intent of Requirement R3. 2. Based on your comment, the drafting team has designated the interconnecting bus in the example figures to provide clarity.		

Organization	Yes or No	Question 5 Comment
3. As noted in Figure 4 above, the Interconnected Element between the Transmission Owner and the Distribution Provider is the transmission line or tap between the line and Breaker C.		
FirstEnergy	Yes	FirstEnergy supports the change described by Question 5. Other comments from FirstEnergy in addition to the specific questions asked by the drafting team: A) PRC-001-3 EFFECTIVE DATE: The PRC-001-3 standard needs to be edited to match what is stated in the Implementation Plan. The Implementation Plan indicates that both PRC-027-1 and PRC-001-3 will become effective at the same time which is stated as being the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. However, the PRC-001-3 standard in its Effective Date section indicates the first day of the first calendar quarter twelve months following applicable regulatory approval. B) PRC-001-3 VERSION HISTORY: The Version History of the PRC-001-3 standard needs some clean-up. The table reflects a "version 4" however this project creates version 3. Looks l+A74ike the fix is to delete the row labeled version 3 and change the version 4 to reflect 3. The description text in that row is correct. C) PRC-001 VERSION CHANGES: NERC needs to consider what it plans to do with the existing NERC BoT Approved versions PRC-001-1.1 and PRC-001-2 which have yet to be filed with FERC. It is recommended that NERC suspend the filing of those standards, keep it simple and file PRC-001-3 with this project. This will avoid undo industry confusion and transition. D) PRC-001-3 MISC CLEAN-UP: Section D, Part 1.1 revise Compliance enforcement authority" to read "Compliance Enforcement Authority (CEA)". This is a defined glossary term and is shown capitalized in other areas of the standard. In the second sentence, capitalize "entity" in the reference to "Regional entity".

Organization	Yes or No	Question 5 Comment
		E) PRC-001-3 R1: Seems odd to have a standard with only one requirement. The requirement states "Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area." FE proposes that R1 or an alternate be moved to PER-005.
Response: Thank you for your comment. **A) The drafting team made the change to the Effective Date language.** **B) The drafting team made the change to the Version History.** **C) Based on the projected approval date of this Standard your suggestion may not be possible; however, this will be investigated based on the results of the next posting.** **D) The suggested change has been made.** **E) The drafting team did add Measure M1, which reads: “For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel.” The drafting team recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.**		
National Grid and Niagara Mohawk (A National Grid Company)	Yes	National Grid offers the following additional comments that do not pertain to Question 5. The comments are included here since the Comment Form did not have an additional question concerning if we had additional comments. 1. Page 4: Other Aspects of coordination of Protection Systems addressed by other Project needs to be included in the final standard since it delineates what is not included in this one. 2. Page 8: Para.R2.1.2 should be reworded as it allows for a series of increments in fault current each less than 10% but which when summed over a number of review periods could collectively exceed 10%. 3. Application Guidelines: a. Page 21: “Data used to determine Fault currents....” is essentially the short

Organization	Yes or No	Question 5 Comment
		circuit model and the associated data base of line, transformer and generator impedances and connections. If that what is expected then it should be so stated otherwise “data” leaves a lot open to the reader’s conjecture. b. Page 25: Decision point regarding R2.1.2 has the same issue as identified above in comment 2. c. Diagrams Fig. 1, 2, 3, 4, 5: The text that goes with these diagrams is inappropriate in its assignment of responsibilities for who reviews what coordination and the change of wording from “verify” to “review” does not resolve this problem. It is a protection system owner’s responsibility to coordinate their system with adjacent systems and it is the same owner’s responsibility to model adjacent systems in sufficient detail to enable that owner to perform that coordination. 4. Fig . 2, 5: The text refers to “generator protection” which can mean a wide range of protection functions such as but not limited to those related to voltage, frequency, loss of field, over-excitation and more. These were excluded on page 4 of the standard and their exclusion here should be emphasized. 5. Fig. 3, Notes following figure 3 exclude reverse power as being a protection system installed to detect faults on the BES Transmission System. We disagree. In our system and other systems in NE reverse power was historically installed specifically to detect and clear backfeed to a faulted transmission system.

Response: Thank you for your comment.

1. **Those are included in the Background Section of the standard and will remain in the BOT approved version of the standard.**
2. **The drafting team modified the Rationale box for Requirement R2 for clarification in response to your comment.**

3a **The drafting team revised the language by removing the phrase “Data used to determine Fault currents…” for clarification in response to your comment.**

3b **The drafting team revised the diagram for clarification.**

3c **The drafting team revised the Figures for clarification.**

4. **The drafting team revised the Figures and the text for clarification**

Organization	Yes or No	Question 5 Comment
5. Per the note in the referenced figure, reverse power relays are 'often' installed for purposes other than that you describe. In your case where the reverse power relays are installed to provide the protective function, they should be included in the coordination review.		
Certain Members of the ISO RTO Council	Yes	NERC must continue to correct such requirements, as it is not the responsibility of the entity subject to a requirement to ensure another party acts.
Response: Thank you for your comment. The SDT modified the language to better clarify the intent.		
SERC Protection and Controls Subcommittee (PCS	Yes	Other comments (not associated with Question 5) are being provided which could not be addressed in the questions listed above: 1). R2 requires short circuit study every 24 months even though the SDT's own rationale is that other requirements will trigger Protection System Studies first. Thus R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. 2). Please replace "detect Faults on the BES Transmission System" with "protect the BES Transmission System" in all three places it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 3). VSL escalation in 10 days is not representative of the severity of the violation. The SDT correctly points out in R1 rationale that it "has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements." Many entities have numerous Interconnected Elements, and recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity's Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively.

Organization	Yes or No	Question 5 Comment
		Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation. 4). Throughout the 1st and 2nd draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.1.1, R2.1.2, R2-2.2, R4-4.1, R4-4.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. We appreciate the Drafting Teams perspective, but the SERC PCS believes that such cross references are confusing. 5). Under R1 - MI measure wording does not read as a completed statement. Suggest removing ‘that’ from the first sentence. 6) The process chart is a direct indication that this process and undertaking for entities will be overwhelming. New systems will be required to track many details of timeframe requirements and communication dates. Additional resources will be required placing increased workload for an effort to change the process that already works for us when working with other entities. The Drafting Team indicated, ‘there is no evidence there is widespread miscoordination of protection systems.’

Response: Thank you for your comment.

1. **The drafting team does not see the direct correlation between the studies required in this standard and the noted studies in the TPLs. However, the drafting team revised Requirement R2 to 60 calendar months to align with Requirement R1.**
2. **The drafting team declines to make the suggested change; however the wording in the figure has been modified for consistency.**
3. **The drafting team revised the VSLs for Requirement R2.**
4. **The references that you indicate have been approved as appropriate way of accomplishing the objective of this standard.**
5. **The drafting team revised Measure M1 as you suggested.**
6. **The drafting team believes the requirements, as written, contribute to the reliability of the BES by requiring entities to**

Organization	Yes or No	Question 5 Comment
coordinate their Protection Systems associated with Interconnected Elements.		
Texas Reliablity Entity	Yes	OTHER COMMENTS (not responsive to any specific question asked above): 1. R2.2: We suggest a minor change "...indicates a deviation in ***single line to ground or 3-phase*** Fault current of 10% or greater ....” 2. R3.1: Based on recent work by the Protection System Misoperation Task Force (PSMTF), changes in logic settings should also be included (e.g. directionality V/Q logic, trip equations, carrier echo logic and coordination timers, carrier dip switch settings, etc.). We would suggest modifying the first bullet to say”...modification of: protective relays or protective function or logic settings, communication systems,....” 3. The SDT may also want to consider adding an item to the list - “Changes to the transmission system topology that change the equivalent impedance or fault current.”
Response: Thank you for your comment. **1. The drafting team made the suggested change.** **2. The drafting team believes the protective ‘logic settings’ used for Protection System coordination are included in the “protective function settings” and declines to make the suggested change.** **3. The drafting team believes that “Changes to the transmission system topology that change the equivalent impedance or fault current” would be captured by the periodic short circuit studies. The drafting team believes the second bullet addresses the situation as well, it reads: “Changes to a transmission system Element that alter any sequence or mutual coupling impedance.”**		
Georgia Transmission Corporation	Yes	Repeat of SERC PCS Other comments are being provided which could not be addressed in question 1 - 5 listed above: 1). R2 requires short circuit study every 24 months even though the SDT’s own rationale is that other requirements will trigger Protection System Studies first. Thus R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for

Organization	Yes or No	Question 5 Comment
		FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. 2). Please replace “detect Faults on the BES Transmission System” with “protect the BES Transmission System” in all three places it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 3). VSL escalation in 10 days is not representative of the severity of the violation. The SDT correctly points out in R1 rationale that it “has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements.” Many entities have numerous Interconnected Elements, and recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity’s Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively. Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation. 4). Throughout the 1st and 2nd draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.1.1, R2.1.2, R2-2.2, R4-4.1, R4-4.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. We appreciate the Drafting Teams perspective, but the SERC PCS believes that such cross references are confusing. 5). Under R1 - MI measure wording does not read as a completed statement. Suggest removing ‘that’ from the first sentence. 6) The process chart is a direct indication that this process and undertaking for

Organization	Yes or No	Question 5 Comment
		entities will be overwhelming. New systems will be required to track many details of timeframe requirements and communication dates. Additional resources will be required placing increased workload for an effort to change the process that already works for us when working with other entities. The Drafting Team indicated, 'there is no evidence there is widespread miscoordination of protection systems.'
Response: Thank you for your comment. 1. **The drafting team does not see the direct correlation between the studies required in this standard and the noted studies in the TPLs. However, the drafting team revised Requirement R2 to 60 calendar months to align with Requirement R1.** 2. **The drafting team declines to make the suggested change; however, the language in the noted figure has been updated for consistency.** 3. **The drafting team revised the VSLs for Requirement R2.** 4. **The references that you indicate have been approved as appropriate way of accomplishing the objective of this standard.** 5. **The drafting team revised Measure M1 as you suggested.** 6. **The drafting team believes the requirements, as written, contribute to the reliability of the BES by requiring entities to coordinate their Protection Systems associated with Interconnected Elements.**		
Idaho Power Co.	Yes	1. R1 The requirement is written to be applicable to Transmission Owners. In our case we have several lines where we do not own the Interconnecting Element, but operate the Protection System at one terminal. Based on the Glossary, we believe this makes us a Transmission Operator. If this interpretation is accurate, there would seem to be a gap in the Applicability of the Standard, as it does not include the Operator. 2. R2 We are wondering why this Requirement is only applicable to the Transmission Owner. Should it not be applicable to all the functional entities similar to the language used in R1, R3, and R4? General comments 3. In reviewing the Standard, there was confusion related to the Protection System Study and what the 10% was measured against. We believe that the

Organization	Yes or No	Question 5 Comment
		Protection System Study referred to in the Standard is that group of faults and contingencies used to create the in-service settings of the relay. Could this be clarified? 4. Additionally, the exchange of information between Functional Entities is a critical part of PRC-027, however, no mechanism is in place to ensure proper contact information is available. Employee movement within a utility may render contact information obsolete. In addition, Independent Power Producers, such as wind farms, are not typically staffed by local personnel or by individuals with a knowledge of System Protection. Because PRC-027 relies so heavily on the exchange of information it is not sufficient to simply place time lines on the transfer of data between Functional Entities. Additional controls to ensure that these data requests reach the appropriate people is needed.
Response: Thank you for your comment. **1. If you are a registered Transmission Owner and own the Protection System, you are responsible for the coordination of the Protection System.** **2. As noted in the Guidelines and Technical Basis section: In Requirement R2, the Transmission Owner is identified as the Functional Entity responsible for performing the Fault current studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.** **3. The intent is that the 10% be measured against the Fault currents that were available at the interconnected bus at the time the last Protection System Coordination Study was done.** **4. The drafting team agrees that entities must have accurate contact information for this standard as well as the existing requirements in PRC-001 but ensuring contact information is kept current is beyond the scope of this standard.**		
Northeast Power Coordinating Council	Yes	We agree with the change. However, we are adding a comment on the VRFs. The VRFs should be High, not Medium. There are similar requirements in PRC-023-2 Transmission Relay Loadability, and TPL-001-2 Transmission System

Organization	Yes or No	Question 5 Comment
		Planning Performance Requirements which have a High VRF. Also, from the Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 - Protection System Coordination for Performance During Faults, the FERC VRF G4 Discussion reads “Guideline 4- Consistency with NERC Definitions of VRFs: Failure to perform a Protection System Study for each Interconnected Facility to verify that Protection Systems coordinate such that the least number of power system Elements are isolated to clear Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC’s definition of a Medium VRF.” Poor protection system coordination during a disturbance can create severe system conditions faster than Operators can respond to them, leading to system instability or a cascading failure. These circumstances are consistent with the NERC definition of a High VRF.
Response: Thank you for your comment. **The drafting team assigned the VRFs in accordance with the NERC criteria and FERC guidelines for establishing VRFs, and believes the assigned risk factors are appropriate.**		
Pepco Holdings Inc & Affiliates	Yes	We agree with this change. However, we have several other comments concerning this standard in addition to those expressed in response to Questions 1 thru 5. Usually there is a space on the comment form to enter these additional comments. Absent one, we offer these additional comments as an addendum to Question 5. 1) Requirement R2: The phrase “Facility associated with an” contained in R2 is confusing and unnecessary and should be eliminated. R2 should simply read “For each Interconnected Element on its System, the Transmission Owner

Organization	Yes or No	Question 5 Comment
		shall:" 2) Requirement R2, Parts 2.1.1 and 2.1.2: Remove the term "interconnecting bus" and replace it with the phrase "point of interconnection between the Entities." The point of interconnection between the entities is more descriptive in that the interconnection point may not be a physical "bus", but rather the terminals of a line disconnect switch, terminals of a breaker, specific transmission pole, etc. Even though the point of interconnection is often modeled in a short circuit program as a "bus", the term "interconnecting bus" has no physical meaning. 3) Requirement R3, Part 3.3: A footnote should be added stating that this requirement does not apply to those temporary setting changes that sometimes are applied during commissioning, maintenance, or investigative testing activities to verify performance of individual protective elements, provided the original settings were returned upon the conclusion of the testing activity. For example, in multifunction relays when testing backup time delayed protective elements (i.e., zone distance or time overcurrent elements) it may be necessary to temporarily disable high speed elements (i.e., pilot or zone 1 elements). 4) The SDT states that "the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address the appropriate use of time delays in relays". However, a word search of the 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. The mention of "the appropriate use of time delays in relays" in the 2003 Blackout Report was in the context of the actuating time of relays in response to system overload conditions, and generator protection to voltage and frequency excursions during stressed system conditions. The concern was that relays operated on overload before system operators could react and that some generators tripped

Organization	Yes or No	Question 5 Comment
		(exacerbating the collapse) before other system schemes (UFLS or UVLS) could operate. The solution was not to increase the time delay on Zone 3 relays (which would have been intolerable for fault clearing purposes) but to address the relay loadability issue in PRC-023, to make them immune from operating under heavy load conditions. Similarly the premature tripping of generators on voltage and frequency protection during stressed system conditions (not fault conditions) and coordination with system UFLS and UVLS schemes was discussed in the report. Likewise those issues have now been addressed, or are being addressed, in PRC-006, PRC-010, PRC-022, PRC-019, and PRC-024. Similarly in the recent Southwest Blackout of 2011 the operation of relay schemes during overload conditions was a contributing factor. There was again no evidence of miscoordination of relay schemes during fault conditions. The unexpected operation of relays and SPS's during overload conditions could have been avoided by proper application of existing standards PRC-023 and PRC-014-0. Based on the above, where is the historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions? Reliability Standards should be adopted based on a need to address a known, or probable, reliability issue. As such, although we support the overall desire to ensure that protective systems are "properly coordinated"; we see little value in developing a new Reliability Standard to address something that is routinely practiced and which has not been demonstrated to be a contributor to major system disturbances, or cascading outages. Even the SDT in their rationale for Requirement R1.1 stated that they have no evidence that there is widespread miscoordination between Interconnected Facilities. In lieu of a formal standard to address relay coordination during faults, a simple technical reference document on Protective System Coordination issues may provide equal benefit to the industry.The above comment was also submitted with Draft 1 of the standard. In their response the SDT stated that PRC-027 was being developed in response to FERC Order 693. However, Order 693 only directs NERC to address specific deficiencies in PRC-001 surrounding certain measures and levels of non-

Organization	Yes or No	Question 5 Comment
		compliance relating to the notification and response to the detection of failures in relay protection systems. As such, we believe PRC-027 goes well beyond what is was directed by FERC, and the stated purpose of the SAR. We urge the SDT to revisit FERC Order 693 and revise this standard as appropriate to address only the stated FERC directives.
Response: Thank you for your comment. 1. **The drafting team made the suggested change.** 2. **The drafting team considered this alternative previously; however the "point of interconnection between the Entities' can sometimes be at a given point on the line and in some cases neither entity may own the line itself. Therefore the present language was deemed sufficient.** 3. **The drafting team believes temporary settings changes are addressed in TOP-002, which incorporated Requirements R5 and R6 from PRC-001-1. Temporary settings applied (or changed) to perform maintenance testing of a relay would not have an effect upon overall coordination of the Protection System, as the relay would likely be taken out of service for such testing.** 4. **Although the drafting team does not necessarily disagree with your assessment of the language in the "Final Report on the August 14, 2003 Blackout in the United States and Canada" the drafting team does believe that the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the subject result, which identified the need to address "the appropriate use of time delays in relays," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination. The drafting team is operating within the scope the approved SAR, which includes recommendations in addition to those in FERC Order 693, and declines to remove the reference to Recommendation 21C from the Background section of the draft standard.**		
Southern Company	Yes	1. We believe that the proposed standard is too prescriptive regarding the specific duties and multiple time frames of each of the parties TO,GO, and DP. Including time frames for each Interconnect Element with regard to effective dates (6 mo), initial studies (48 mo), studies triggered by change of equipment or change of fault current (6mo), TO/GO/DP agreed upon schedules (variable), delivery of studies (90 days) , short circuit studies (24 mo), notification to others of fault current changes (30 days), change detail notification (30 days), and review of summary results (90 days) is unnecessary and unduly burdensome. The process flow chart provided on page 22 of the draft standard is evidence of

Organization	Yes or No	Question 5 Comment
		the complexity of the proposition. Please seriously consider the following simplified three-requirement approach which will similarly accomplish the desired outcome of coordination of the Protection System for Interconnected Elements. R1). Require the two parties of the Interconnecting Element to jointly develop a Protection System Study- initially with X months to complete. R2). Require a review/update of the protection system study for proper coordination anytime a change to the system may upset coordination. R3). Require a review/update of the protection system study for proper coordination every X years. The corresponding measures for each proposed requirement could be... M1: has a protection system study been performed by the initial required date? M2: has a protection system study been reviewed/updated for system changes which impact the coordination? M3: has the protection system study been reviewed/updated every X years? During an audit period these requirements and measures will drive entities to establish and maintain protection system studies. This approach keeps the focus on the protection system study rather than the multiple actions with varying time frame restrictions. We believe that these changes will result in an equally effective driver to establish coordination while keeping the standard as succinct as possible. 2. In general, for protection on the transmission line leaving the plant, the generator owner should be responsible only for coordinating with the first set of line relaying encountered when proceding across the interconnecting element. He should not be responsible for coordinating with relaying at the opposite end of the interconnecting element. For example, in Figure 5 on Page 28 of the draft standard, Generator Owner T should not have to worry about a

Organization	Yes or No	Question 5 Comment
		review of the relaying located at breakers G, F, or E. Another example is Figure 2, Page 25 of the draft standard: Generator Owner R should not be responsible for reviewing the relaying at the breaker C.
Response: Thank you for your comment. **1. The drafting team believes the standard, as written, is necessary to ensure the reliability objectives are met.** **2. The drafting team agrees with your statement. Figure 5 is included for the unique situation that the owner of the interconnecting bus may not be the owner of the Protection System. The following note has been added to Figure 5: Note: In a large majority of cases, Figure 2 would be applicable for most generator interconnections. In Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T.**		
Southwest Power Pool Reliability Standards Development Team	Yes	
GP Strategies	Yes	
Luminant	Yes	
Hydro One Networks Inc.	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
JEA	Yes	
US Bureau of Reclamation	Yes	
Operational Compliance	Yes	
pacificorp	Yes	

Organization	Yes or No	Question 5 Comment
Western Electricity Coordinating Council	Yes	
Dynegy	Yes	
American Transmssion Company, LLC	Yes	
Essential Power, LLC	Yes	
Wisconsin Electric Power Company	Yes	
Liberty Electric Power LLC	Yes	
Public Service Enterprise Group	Yes	
Ameren	Yes	
Entergy Services, Inc. (Transmission)	Yes	
Exelon Corporation and its affiliates	Yes	
Cogentrix Energy Power Management, LLC	Yes	
Kansas City Power & Light	Yes	
City of Tallahassee	Yes	
NV Energy	Yes	
ATCO Electric		Additional comments from AE that does not fit any specific question: (1) Timelines: There are too many hard timelines that aren’t consistent between

Organization	Yes or No	Question 5 Comment
		individual requirements (24 months, 6 months, 90 days, 30 days, agreed upon time frame, prior to implementation, etc.). Keeping track of these timelines and evidence gathering will take considerable time and effort. Can the drafting team reduce the amount of timelines to make this standard manageable? Can the drafting team anticipate how to audit this standard during the standard development process? (2) There are requirements referred to other requirements and vice versa. Can the drafting team not to refer the requirements back and forth? Can the drafting team anticipate how to audit this standard during the standard development process?
Response: Thank you for your comment. 1. **The drafting team believes the timelines are necessary to ensure the reliability objectives of the standard are met. The drafting team can't anticipate audit procedures; however, members of the drafting team will be involved in the development of the RSAW.** 2. **The drafting team can't anticipate audit procedures; however, members of the drafting team will be involved in the development of the RSAW.**		
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and**		

Organization	Yes or No	Question 5 Comment
communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise some of the VSLs.		
Midwest Reliability Organization NERC Standards Review Forum		In addition to the previous comments outlined above, the NSRF offers the following comments for the drafting team's consideration. 1. Recommend the timeframes in R1.1.1 and R2.1 be stated in calendar years. The NSRF is concerned that a utility would be found in violation of this standard if one study was done in February of 2012 and the next one in March 2014 based on the current wording. The intent of a results-based standard is not to have these types of technicalities built into them. 2. An entity cannot study a part of the system that they do not own. The examples at the end of the draft in the Application Guidelines appear to imply that they should. Settings should be obtained from remote ends of a tie line only to be used in conjunction with studying the settings for which an entity has direct control. If an entity can't issue setting changes for a relay, then the entity can't study it to see what the settings should be. If both ends need adjustment then an iterative coordination back and forth between Entities should be performed. The majority of utilities would not feel comfortable accepting an external entity's settings changes for their own equipment. Recommend additional wording be added to the Application Guidelines to the further clarify the drafting team's intent. 3. R2, Part 2.1.1: Recommend R2, Part 2.1.1 be revised to only require short circuit values be 'studied' at buses for which the entity in question specifically owns. For Interconnected Facilities between two entities, fault current values should be 'requested' by the neighboring utility. This would be beneficial to ensure that both entities are comparing models to keep them as up to date as possible. Better yet are boundary equivalents as discussed in previous

Organization	Yes or No	Question 5 Comment
		comments. 4. R2, Part 2.2: Similar to our previous comment for R1, Part 1.2, the proposed language in Part 2.2 appears to indicate that internal Interconnected Elements would require additional documentation and notification beyond what is necessary. This should only be required of Interconnected Elements in which there are two or more owners. Proof of study should be adequate for internal situations. 2.2 Within 30 calendar days after identification where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates a deviation in Fault current of 10% or greater, provide each owner of the Protection System associated with the Interconnected Element, that include two or more Registered Entities, the updated Fault current values (Iscs).
Response: Thank you for your comment. 1. **The drafting team increased the timeframes for both requirement parts to 60 calendar months; however declines to make the suggested change to calendar years.** 2. **The drafting team does not agree with the issue as stated. Settings obtained from remote ends of a tie line would be used to ensure no coordination issues exist with other setting on its system. If coordination issues are identified, then the drafting team agrees that it may be an iterative process for the two entities to come to a mutual solution.** 3. **Requirement R2 has been revised. The drafting team believes that the Requirement R2, Part 2.1 indicates that the entity is conducting the study at their interconnecting bus: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus.** 4. **Requirement R2 has been revised. The drafting team believes that Requirement R2, Part 2.1 indicates that the entity is conducting short circuit studies only for their interconnecting bus(s).**		
PJM Interconnection		PJM supports revising the language in Requirement 1 of PRC-001 by replacing the term 'familiar.' This word is ambiguous and confusing in terms of the specific expectations of the applicable functional entities regarding the purpose and limitations of protection system schemes applied in its area.
Response: Thank you for your support.		

Organization	Yes or No	Question 5 Comment
The drafting team is not revising the language of the remaining requirement of PRC-001, but is providing a measure.		
ReliabilityFirst		ReliabilityFirst offers the following comments on the VSLs for consideration: 1. Requirement R3 VSL a. ReliabilityFirst believes VSL for Requirement R3 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement." Requirement R3, Part 3.1 and 3.1 requires the entity to provide "details" and the associated VSLs references "information". ReliabilityFirst recommends the SDT modify the VSL to be consistent with the language in the requirement. b. It is unclear which requirement the last VSL under the "Severe" category is referring to. ReliabilityFirst recommends adding the Part number in which the VSL is associated with. 2. Requirement R4 VSL a. ReliabilityFirst believes VSL for Requirement R4, Part 4.1 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement." The VSLs associated with Part 4.1 use the language "confirmed acceptance" though the language in the actual Part talks about review of summary results and response as to whether further action is required. ReliabilityFirst recommends the SDT modify the VSL to be consistent with the language in the requirement as follows: "The responsible entity reviewed the summary results of a Protection System Study and responded as to whether further action is required per R4, Part 4.1, but was late by 10 calendar days or less"
Response: Thank you for your comment. **1a The drafting team made the suggested change.** **1.b The drafting team made the suggested change**		

Organization	Yes or No	Question 5 Comment
2.a. The VSL language has been modified to be consistent with the revised Requirement 4, Part 4.1.		
Consumers Energy		The following comments are unrelated to Question 5. However, there has not been a question/section added for other/general comments. 1) In the process flow chart (page 22) the R2.2 box which states "Within 30 days, provide each owner of the Protection System associated with the Interconnected Element", we believe the key element, "the updated Fault current values" was not included in this statement. 2) In reading the Example Process on page 23, we were expecting to be able to follow it through the process flow chart on page 22 as one possible example to guide you through the standard process. As it started off as a request for information, we assumed the flow process started in the R3 box "Data request" which indicates no further action. Yet the example process continues on. We would suggest an improved explanation paragraph be added to the "Example Process" to better clarify what the example is intended to illustrate.
Response: Thank you for your comment. **1. The drafting team revised the flow chart to be consistent.** **2. The drafting team revised the flow chart to be consistent.**		
ATCO Electric (AE)		Requirement R1.1.2 – A 10% change in fault current isn't much in some areas of AE's system, perhaps as little as a few hundred amps. This could lead to a burdensome requirement to frequently review the same areas of our system. Ten percent seems fairly restrictive when we typically use safety margins of 40% to 50% in selecting instantaneous overcurrent settings
Response: Thank you for your comment. **As noted in the Guidelines and Technical Basis section: The drafting team investigated various inputs that would trigger a review of the existing Protection System Studies and determined, through the experience of the drafting team members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an**		

Organization	Yes or No	Question 5 Comment
appropriate indicator that an updated Protection System Coordination Study may be necessary. In the situation that you described, the standard provides the entities the opportunity to 'technically justify why such a study is not required'. Also note that the requirement to conduct the review has been modified to 60 [calendar] months.		

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Draft 1 of SAR posted for comment June 11, 2007 – July 10, 2007.
2. SAR approved on August 13, 2007.
3. First posting of revised standard PRC-001-2 on September 11, 2009.
4. Transitioned from a revision of PRC-001-1 to development of PRC-027-1 based on industry comments, Quality Review feedback, and consideration of FERC directives relative to the existing requirements of PRC-001-1.
5. Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012.
6. Draft 2 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from November 16 – December 17, 2012.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPC SDT) created a new results-based standard, PRC-027-1,with the stated purpose 'to coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.' This standard incorporates and clarifies the coordination aspects of Requirements R2 and R3 from PRC-001-2 (formerly R3 and R4 of PRC-001-1). The SPC SDT is requesting a posting for stakeholder comments for a 30-day formal comment period with a parallel successive ballot.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period with Parallel Successive Ballot	June 2013
Conduct Recirculation Ballot	August 2013
BOT Adoption	November 2013

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is 12 months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. For Interconnected Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2007-06 – PRC-027-1	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here.

The following terms are defined for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

Interconnected Element: A BES Element that electrically joins facilities owned by:

a) separate Registered Entities, or
b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

Protection System Coordination Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Coordination for Performance During Faults**

2. **Number:** PRC-027-1

3. **Purpose:** To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2 **Facilities:** For the purpose of the requirements contained herein, the following Protection Systems owned by each Functional Entity in 4.1 above are those to which these requirements are applicable.

   4.2.1 Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements

5. **Background:**

On December 7, 2006, the NERC Planning Committee approved the assessment of Reliability Standard PRC-001 – System Protection Coordination, prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF noted problems with the applicability to entities and vagueness of requirements in the existing PRC-001-1 reliability standard. The SPCTF concluded that the deficiencies of Reliability Standard PRC-001-1 were magnified by having requirements that addressed coordination of protection functions and capabilities in the operating and planning timeframes. Consequently, the SPCTF recommended that the requirements for the operating horizon and planning horizon be clearly delineated, and possibly divided into two standards.

The NERC Standards Committee approved a Standard Authorization Request that included the modifications noted by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC SDT) posted an initial draft of Reliability Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC SDT attempted to address all issues identified by the SPCTF assessment of PRC-001-1. The SPC SDT responded to the comments from the initial posting of PRC-001-2, and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC Quality Review (QR) in December 2010. Based on the results from the QR, and after informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to follow the SPCTF recommendation and focused their knowledge and expertise on developing a new results-based standard, concentrating on the reliability aspects (the coordination of new and existing protective systems in the planning horizon) associated with Requirements R3 and R4 of PRC-001-1. These aspects of coordination are incorporated and clarified in the proposed Reliability Standard PRC-027-1 – Protection System Coordination for Performance During Faults with the stated purpose:

> *"To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults."*

Additionally, the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address "the appropriate use of time delays in relays," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination.

PRC-001-1 contained a non-specific training requirement (Requirement R1), three operating time frame requirements (Requirements R2, R5 and R6), and two planning requirements (Requirements R3 and R4). The SPC SDT transferred the responsibility of addressing the operating Requirements R2, R5, and R6 to the drafting team for Project 2007-03 Real-time Operations, charged with revising the TOP group of reliability standards. The Project 2007-03 drafting team retired Requirements R2, R5, and R6 of PRC-001-1 because they addressed data and data requirements that are now included in Reliability Standard TOP-003-2. The NERC Board of Trustees adopted Reliability Standards TOP-003-2 and PRC-001-2 on May 9, 2012.

The SPC SDT revised PRC-001-2. Revisions include the removal of Requirements R2 and R3 (formerly Requirements R3 and R4 of PRC-001-1). These two legacy requirements are being retired because the aspects of coordination they address are incorporated in the proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The SPCSDT believes the training aspects of Requirement R1 would be more appropriately addressed by the PER group of Reliability Standards. Consequently, the drafting team has recommended via the NERC Issues Database that the future drafting team charged with revising PER-005-1 incorporate the reliability objective of Requirement R1 into the revised standard. Until that occurs, Requirement R1 of PRC-001-2 must remain in the standard. In an effort to improve PRC-001-2 until it can be fully retired, the drafting team has provided a measure to accompany Requirement R1. The Applicability section was also updated to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)

Other Aspects of Coordination of Protection Systems Addressed by Other Projects:

Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects.

- Underfrequency Load shedding programs are addressed in PRC-006-1. Generator performance during frequency excursions is being addressed in PRC-024-1 by Project 2007-09 Generator Verification.

- Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed in PRC-024-1 by Project 2007-09, Generator Verification.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is being addressed in PRC-019-1 by Project 2007-09.
- Transmission relay loadability is addressed in PRC-023-2.
- Generator relay loadability will be addressed in PRC-025-1 by Phase 2 of Relay Loadability: Generation, in Project 2010-13.2.
- Protective relay response during power swings will be addressed by Phase 3 of Project 2010-13.3, Relay Loadability.
- Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and will be improved in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

The SPC SDT believes that including these other aspects of protection coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

B. Requirements and Measures

Rationale for R1:

Part 1.1 A Protection System Coordination Study (PSCS) is necessary to verify coordination of Protection Systems for existing and new Interconnected Elements. The drafting team defines the term "Interconnected Element" as "A BES Element that electrically joins facilities owned by: a) separate Registered Entities, or b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner)."

Part 1.1.1 The drafting team believes 60 calendar months is an appropriate period of time for entities to perform the PSCS required where no study exists. The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame.

Part 1.1.2 The drafting team believes that 12 calendar months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater Fault current change at an interconnecting bus, where such conditions may warrant a new PSCS, or to technically justify why no such study is required, e.g., when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current.

Part 1.1.3 The drafting team believes that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, or to technically justify why no such study is needed. The drafting team believes the timeframe associated with the requirement for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3, Part 3.1 is unnecessary because notification of such a change may occur weeks or years prior to the change. The initiating entity has the incentive to provide the identified information as soon as possible to ensure timely implementations. The drafting team believes that six months is an appropriate period of time for entities to perform the studies required or to technically justify why no such study is needed when details of changes are provided associated with Requirement R3 Part 3.3.

Part 1.2 The drafting team believes to properly ensure coordination of Protection Systems associated with Interconnected Element(s), all entities need to share the summary of results of a PSCS and assess the study results. The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS performed in accordance with Requirement R1, Part 1.1 to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s).

Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by both Registered Entities.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

1.1. Perform a Protection System Coordination Study (PSCS) for each of its Interconnected Elements as follows:

1.1.1 Within 60 calendar months after the effective date of this standard, if no PSCS for that Interconnected Element exists.

1.1.2 Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required.

1.1.3 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or within six calendar months of being notified of a change as described in Requirement R3, Part 3.3; or technically justify why such a study is not required.

1.2. Within 90 calendar days after the completion of each PSCS, provide to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s), a summary of the results of each PSCS performed pursuant to Requirement R1, Part 1.1, (including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed).

M1. Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1. and 1.1.2, and 1.1.3 is a dated PSCS, or the summary results of each PSCS (hard copy or electronic file formats) demonstrating the time frames specified or agreed to in Parts 1.1.1, 1.1.2, and 1.1.3 were achieved. Acceptable evidence of a technical justification for not performing a PSCS as specified in Parts 1.1.2 and 1.1.3 may include, but is not limited to, documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any aspects of coordination.

M2. Acceptable evidence for Requirement R1, Part 1.2 is dated documentation demonstrating that the summary results of each PSCS (hard copy or electronic file formats) were provided within the specified time frame to the owner(s) of the Protection System(s) associated with the Interconnected Element(s).

Rationale for R2: This requires a periodic review of Fault currents at the interconnecting bus and providing the results to the applicable entities when changes occur that meet the criteria of Requirement R2. It is important that interconnected Facility owners are kept aware of changes that could affect proper performance of their Protection Systems. The Transmission Owner is identified as the entity responsible for performing the short circuit studies because they maintain the data necessary to perform the studies. Note: short circuit studies are used to determine the Fault current values at the interconnecting bus where a PSCS exists. These studies are typically performed assuming maximum generation and all Facilities in service.

The drafting team believes 60 calendar months provides the entities flexibility to either technically justify why Fault current does not affect the Protection System coordination, or schedule and perform the activities specified in Requirement R2, Parts 2.1 and 2.2.

The drafting team recognizes the coordination of some types of Protection Systems is unaffected by changes in Fault current and, where technically justified, can be exempted from the short circuit review.

Part 2.1 The drafting team believes maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus are necessary quantities needed to review the coordination.

Part 2.2 The drafting team is including this equation to assure a consistent approach is used by each Transmission Owner when calculating the percent change in Fault current values.

Part 2.2.1 The drafting team believes the 30-calendar day time frame is reasonable for providing the Fault current information to the owner(s) of the Protection System(s) associated with the Interconnected Element. The drafting team determined that a change in Fault current of 10% indicates an appropriate point at which to provide this information, based on the fact that Protection Systems are typically set with margins above 10%.

R2. For each Interconnected Element on its System, the Transmission Owner shall, once every 60 calendar months, technically justify why Fault current does not affect the Protection System coordination, or: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

2.1. Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Coordination Study (PSCS) is available per Requirement R1.

2.2. Calculate the percent change between the Fault current values (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation:

$$\%\ Change = \left|\frac{Iscs - Ipscs}{Ipscs}\right| x\ 100$$

Where: I_{scs} = Fault current value from present short circuit study

And: I_{pscs} = Fault current value used in the most recent PSCS

2.2.1 Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (I_{scs}) to each owner of the Protection System associated with the Interconnected Element.

M3. Acceptable evidence of technical justification for not performing a short circuit study as specified in Requirement R2, could be documented engineering analyses or assessments that demonstrate why Fault current does not impact any aspects of coordination.

M4. Acceptable evidence for Requirement R2, Parts 2.1 and 2.2 is dated documentation (hard copy or electronic file formats) that contains the present Fault current values from the short circuit study for each interconnecting bus analyzed, and identifies the percent change from the Fault current values used in the most recent PSCS determined by the equation.

M5. Acceptable evidence for Requirement R2, Part 2.2.1 is dated documentation (hard copy or electronic file formats) that the updated Fault current values (I_{scs}), were provided within the specified timeframe to each owner of the Protection System associated with the Interconnected Element.

Rationale for R3: This requires the transfer of appropriate information to the entities associated with each Interconnected Element due to circumstances identified in Parts 3.1, 3.2, and 3.3.

Part 3.1 The reliability objective of this requirement is to enable the process of conducting PSCSs by ensuring that the information is provided to the owner(s) of the Protection Systems associated with Interconnected Element(s). The drafting team believes that information about any proposed change or addition (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the Interconnected Element. The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list provided in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. Examples of changes to generator units that result in impedance changes could include replacements and re-ratings. This requirement also pertains to changes identified as a result of studies performed in Requirement 1, Part 1.1.

Part 3.2 The purpose of this requirement is to provide a means for an entity to receive the requested information in a timely manner in order to perform a PSCS, as required in Requirement 1, Parts 1.1.1, 1.1.2, and 1.1.3. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide this information. The requirement also provides some flexibility for the parties involved to determine an otherwise agreed-to schedule, if appropriate.

Part 3.3 The drafting team believes 30 calendar days is sufficient time to provide the information.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnected Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnected Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).

- New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios
- Changes to a transmission system Element that alter any sequence or mutual coupling impedance
- Changes to generator unit(s) that result in a change in impedance
- Changes to the generator step-up transformer(s) that result in a change in impedance

3.2. Requested information related to the coordination of Protection Systems associated with an Interconnected Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule.

3.3. Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.

M6. Acceptable evidence for Requirement R3, Part 3.1 may include, but is not limited to, documentation (hard copy or electronic file formats) demonstrating that a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) as identified in the bulleted list, was provided to each responsible entity connected to the same Interconnected Element.

M7. Acceptable evidence for Requirement R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was provided according to the agreed-upon schedule, or within 30 calendar days absent such an agreement.

M8. Acceptable evidence for Requirement R3, Part 3.3 is dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the changes made was provided within 30 calendar days.

Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with Interconnected Elements affirm that the Protection System(s) applied are acceptable per the conditions identified in Parts 4.1 and 4.2.

Part 4.1 The drafting team believes 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with Interconnected Elements to review the summary results of a PSCS and respond. Note: Per Requirement R1, Part 1.2, at a minimum, the summary results of a PSCS must include the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. The response should indicate acceptance with the review results/conclusions; or rejection of or disagreement with the review results/conclusions and offer of suggestions/modifications to resolve any identified coordination issues. The drafting team recognizes there could be situations where one owner may not agree with the other owner's protection philosophy but they accept the proposed changes since no coordination issues were identified.

Part 4.2 The drafting team believes that proposed changes or modifications (including project schedules) to Facilities associated with the Interconnected Element, as described in Requirement R3, Part 3.1, or modifications suggested in Requirement R4, Part 4.1 must be communicated and accepted prior to the in-service date. Acceptance assures that the coordination of Protection Systems associated with the affected Interconnected Element is achieved.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a PSCS (per Requirement R1, Part 1.2) and respond to the other owner(s):

- Accepting the results, or
- Rejecting the results and suggesting modifications to resolve any identified coordination issues.

4.2. Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the

Protection System(s) changes including the resolution of any identified coordination issues.

M9. Acceptable evidence for Requirement R4, Part 4.1 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement.

M10. Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that, prior to implementation of any proposed Protection System(s) changes or modifications, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System associated with an Interconnected Element shall each keep data or evidence to show compliance with Requirements R1, R2, R3, and R4, and Measures M1 through M10, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner or Distribution Provider that owns a Protection System at a Facility associated with an Interconnected Element is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided the Protection System Coordination Study results in	The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity provided the Protection System Coordination	The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided the Protection System Coordination	The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required but was late by more than 60 calendar days. OR The responsible entity provided the Protection System Coordination Study results in

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			accordance with Requirement R1, Part 1.2, but was late by less than or equal to 10 calendar days.	Study results in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	Study results in accordance with Requirement R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar days. OR The responsible entity failed to perform a Protection System Coordination Study on an Interconnected Element in accordance with Requirement R1, Parts 1.1.1, 1.1.2, or 1.1.3. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2 or 1.1.3. OR The responsible entity failed to provide Protection System Coordination Study results in accordance with Requirement R1, Part 1.2.
R2	Long-term Planning	Medium	For an Interconnected Element on its System,	For an Interconnected Element on its System,	For an Interconnected Element on its System,	For an Interconnected Element on its System,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by less than or equal to 30 calendar days. OR The Transmission Owner performed a short circuit study, as required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days.	the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 90 calendar days. OR The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 90 calendar days. OR The Transmission Owner failed to perform a short circuit study, as required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent change between the Fault currents, according to the equation designated in Requirement R2, Part 2.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnected Element, the updated Fault current values, as required in Requirement R2, Part 2.2.1.
R3	Operations Planning	Medium				The responsible entity failed to provide the owner(s) of the Facility associated with the Interconnected Element, details for any proposed change or addition identified in Requirement R3, Part 3.1. OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the information required in Requirement R3, Part 3.3.
R4	Operations Planning	Medium	The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.	The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.	The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.	The responsible entity responded in more than 120 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The responsible entity failed to review the summary results of the Protection System Coordination Study provided to them in accordance with Requirement R4, Part 4.1. OR The responsible entity failed to respond to the other owners in accordance with Requirement R4, Part 4.1. OR The responsible entity failed to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element accepted the Protection System(s) changes including the resolution of any identified coordination issues, prior to implementation of those changes, as required in Requirement R4, Part 4.2.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Purpose:

To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.

This standard requires that separate Registered Entities communicate with each other to coordinate Protection System components on existing Interconnected Elements; and communicate with each other prior to the energization of new or modified Protection Systems associated with Interconnected Elements. The goal of the coordination is to verify that the Protection Systems intended for sensing Faults will operate in the desired sequence for internal and external Faults on the Interconnected Element.

Requirement R1:

This requirement directs the applicable entities to perform a Protection System Coordination Study (PSCS) for every Interconnected Element to verify coordination of existing Protection Systems where no recent study exists; or when Facility configuration changes are made, or where Fault current changes of 10% or more have occurred. In developing the language to define a PSCS, the System Protection Coordination Standard Drafting Team (SPC SDT) considered various reference books discussing protective relaying theory and application, along with the following description of "coordination of protection" from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Using the reference material cited above as guidance, the drafting team defined the term Protection System Coordination Study (PSCS) for use within the PRC-027-1 Reliability Standard as:

> "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults."

PSCSs comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in PSCSs include maximum generation with the transmission system under normal operating conditions and under single contingency conditions. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and

sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), and adequate directional polarizing quantities.

The drafting team believes applicable entities should have a documented PSCS for each Interconnected Element to validate the Protection Systems associated with those Interconnected Elements perform in a manner consistent with the purpose of this Standard. Additionally, the drafting team believes that 60 calendar months is an appropriate amount of time for entities to perform the initial studies expected under this requirement. This period considers the time some entities may require to create project scopes, acquire proposals, and secure contracts to hire external resources that may be needed to perform the studies. The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with Interconnected Elements that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.

Parts 1.1.2 and 1.1.3 further direct that PSCSs must be completed under the following two circumstances:

1. After notification of an identified 10% or greater change in Fault current (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1), the notified entities must perform a new PSCS of the Interconnected Element or document why a study is not required. The drafting team recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater change in Fault current may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the 12-calendar month time frame associated with this requirement represents a reasonable period to perform the studies that are required after identification by the 60-calendar month Fault current review.
2. After proposing or being notified of a change at a Facility associated with the Interconnected Element, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the proposed or notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the timeframe associated with performing a PSCS for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3, Part 3.1 is unnecessary because notification of such a change may occur weeks or years prior to the change due to the wide variety of conditions that may be associated with a particular change. The drafting team sees the entity initiating any change as having the incentive to move this along in a timely fashion in order to both keep the associated project on schedule

and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2. The drafting team believes that six calendar months is an appropriate period of time for entities to perform the studies required, or to technically justify why no such study is needed, when details of changes are provided associated with Requirement R3 Part 3.3.

Requirement R1, Part 1.2 directs the entity performing the PSCS to provide a summary of the study results to the affected Interconnected Element owner(s). The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS it performed to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s). (Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that meets the requirements for a summary of the results of the PSCS would be sufficient for use by both Registered Entities.) As guidance, the drafting team lists the following inputs and results of a PSCS that may be included in the summary provided pursuant to this requirement:

1. A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Facility, and which were reviewed for coordination of protective relays as part of the study, including the contingencies used in the evaluation.
2. A listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Facility under study.
3. A listing of any issues associated with the relay settings of the other owner(s) at the Facility that were identified by the study.
4. Any proposed revisions to a Protection System or its protective relay settings that were identified by the study.

Requirement R2:

The drafting team investigated various inputs that would trigger a review of the existing PSCSs and determined, through the experience of the drafting team members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated PSCS may be necessary. These variations could result from the accumulation of incremental changes over time. This requirement mandates the Transmission Owner either provide a technical justification stating why Fault current does not affect the Protection System coordination of a specific Interconnected Element or perform a periodic review of Fault currents.

Examples of Protection Systems where technical justifications may be used include:

1. Differential elements
2. Distance elements where infeed is not used in determining reach for the protection scheme.
3. Supervised overcurrent elements enabled by:

- Loss of potential condition
- Some communication assisted tripping
- Switch-Onto-Fault (SOTF)

4. Reverse power, definite time &/or time overcurrent elements:
    - Designed to coordinate during maximum generation with the transmission system under normal operating conditions and under single contingency conditions regardless of Fault current.
    - Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.).

The short circuit study provides the Fault current values used to calculate the percent change between the most recent PSCS and the present Fault current values indicated by the short circuit study performed pursuant to Requirement R2, Part 2.1. This calculation is necessary to identify Fault current changes that must be communicated in accordance with Requirement R2, Part 2.2. Short circuit studies are typically performed assuming maximum generation and all Facilities in service.

The drafting team believes that 60 calendar months is an appropriate interval for technically justifying why Fault currents do not affect the Protection System coordination of a specific Interconnected Element, or for reviewing Fault currents. The drafting team believes studies associated with changes that would affect the coordination in less than 60 calendar months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.2.1 further directs the Transmission Owner to, within 30 calendar days, inform each owner of the Facility associated with the Interconnected Element when short circuit studies indicate that 10% changes in Fault current have occurred at the interconnecting bus(s). The drafting team believes the 30-calendar day time frame associated with this requirement is reasonable for providing the Fault current information to the interconnected entity(s) and is consistent with other NERC reliability standards.

In Requirement R2, the Transmission Owner is identified as the functional entity responsible for performing the short circuit studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.

Requirement R3:

This directs the registered functional entity initiating any proposed change or addition to provide the details to the other affected entities of the Interconnected Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes. Documentation provided to these other owners may include, but is not limited to, power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings. The recipient will incorporate the applicable information into its PSCSs to evaluate whether changes are required.

The list of applicable changes provided in Requirement R3, Part 3.1 is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. The drafting team recognizes that Facility changes at other locations can impact the PSCS of the Facility associated with the Interconnected Element; e.g., the addition of a large autotransformer bank or generator not directly connected to the Interconnected Element. The drafting team believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the drafting team sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2.

Requirement R3, Part 3.2 allows for entities to agree upon a schedule, appropriate to the circumstances, for providing the details needed to conduct a PSCS or, absent such agreement, within 30 calendar days of a request for this information. This requirement provides a means for entities to receive requested information in a timely manner. In consideration of circumstances where the information may not be readily available or may be incomplete due the retirement of personnel, the purging of records, change of ownership, etc., it also provides the flexibility of mutually agreeing to a schedule for exchanging information. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide the requested information where no other agreement exists.

Additionally, this requirement includes a provision for providing details associated with changes to the previously agreed-upon coordination when changes are made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components Based upon the limited number of instances that would occur under such circumstances, the drafting team believes 30 calendar days after determining that changes are required is an appropriate time frame for providing the associated details to affected entities.

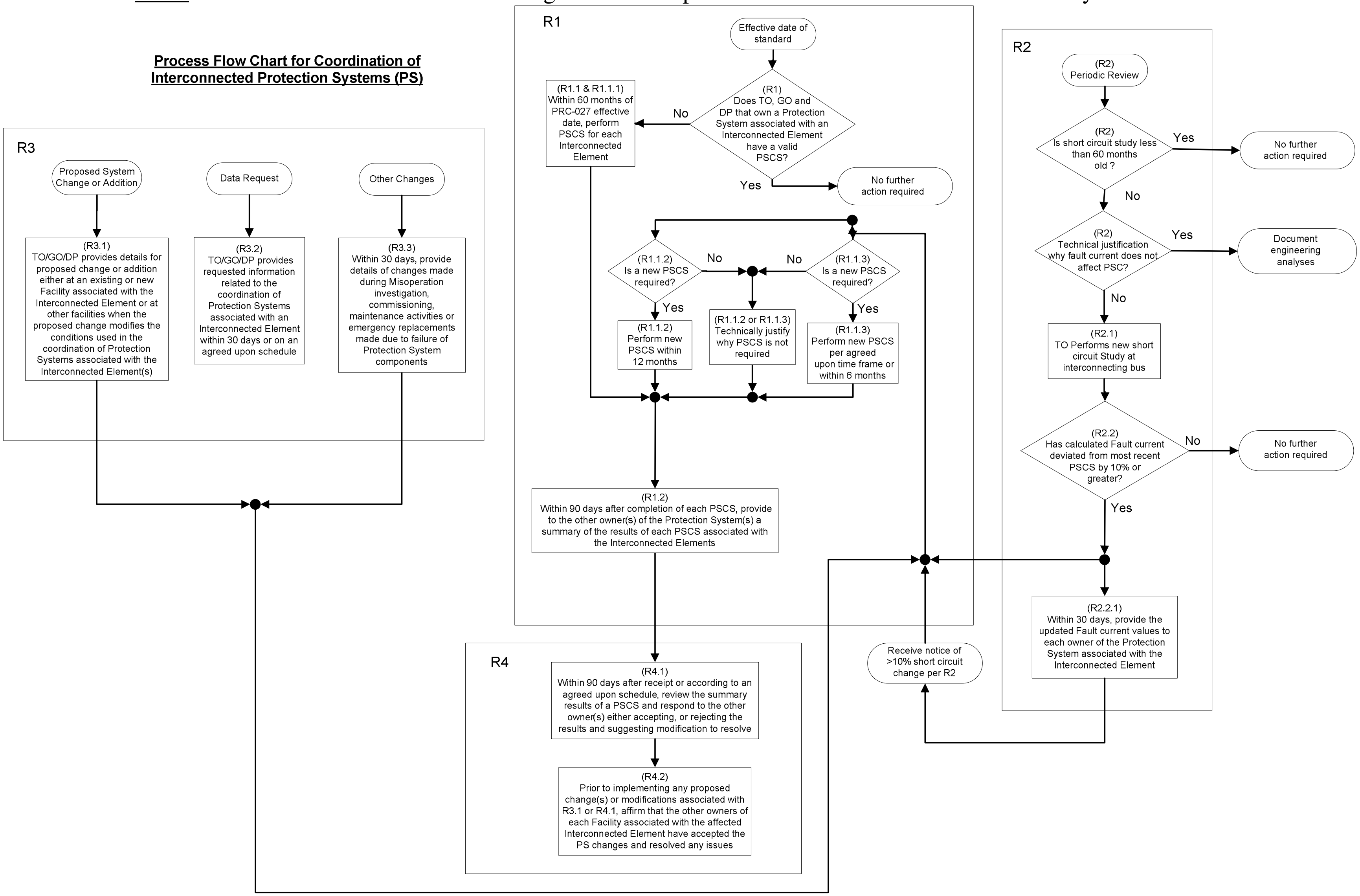
Requirement R4:

The reliability objective of this requirement is to bring the process of Protection System coordination full circle by gaining the confirmation of interconnected entities that their Protection Systems are coordinated consistent with the purpose of this standard. Cooperative participation of Facility owners in communicating Protection System(s) design, and study results will achieve coordination of Protection Systems for reliable operation of the BES during Faults.

Requirement R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to review the summary results of a PSCS, as described in Requirement R1, Part 1.2; and respond as to whether they accepting or rejecting the results, and if rejecting, suggesting modifications to resolve any identified coordination issues. The drafting team believes 90 calendar days after receipt of the results of a PSCS provides a reasonable time for the owners of Facilities to review the summary results of a PSCS.

Requirement R4, Part 4.2 directs entities to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes as described in Requirement 3, Part 3.1 and Requirement 4, Part 4.1 prior to the in-service date of those changes. Any coordination issues identified during the review must be resolved prior to implementing the proposed changes. The purpose of Requirement 4, Part 4.2 is to assure the effects the proposed changes have on Protection Systems at a Facility associated with the Interconnected Element have been considered by all affected entities.

Process Flow Chart: Below is a complete representation of the process, including the relationships between requirements:
Note: All timeframes referenced in the diagram below represent "calendar month" or "calendar day" timeframes.



Example Process

An example of the interaction between entities required to gather the information to perform an accurate study is provided below. This example is given as general guidance only and is not intended to represent all situations that may occur. More detailed examples are provided along with Figures 1-5 in the section that follows this example.

- The initiating entity (Entity A) will contact the interconnected entity (Entity B) and provide details of the proposed change(s) and may also request up-to-date Protection System information.
- Entities A and B will determine whether a new PSCS is required. In this example both agree that a new study is required. The study may be a joint study, individual studies, or a single study provided by Entity A and reviewed and approved by Entity B. In this example, the latter will occur.
- Upon receipt of the above request for information, Entity B will provide the information within 30 calendar days, or an agreed upon time frame.
- Entity A will perform a PSCS using the information received.
- Entity A will provide a summary of the results of the study to Entity B within 90 calendar days of completing the PSCS.
- Entity B will review the summary information and, within 90 calendar days of receiving the study results from Entity A, respond as to whether any coordination issues were identified, and if any further action is required.
    - In cases where the study reveals that changes to Protection Systems are needed, Entity B would propose to Entity A revisions that achieve acceptable results.
    - Ultimately, both entities will collaborate in developing a mutually acceptable solution.

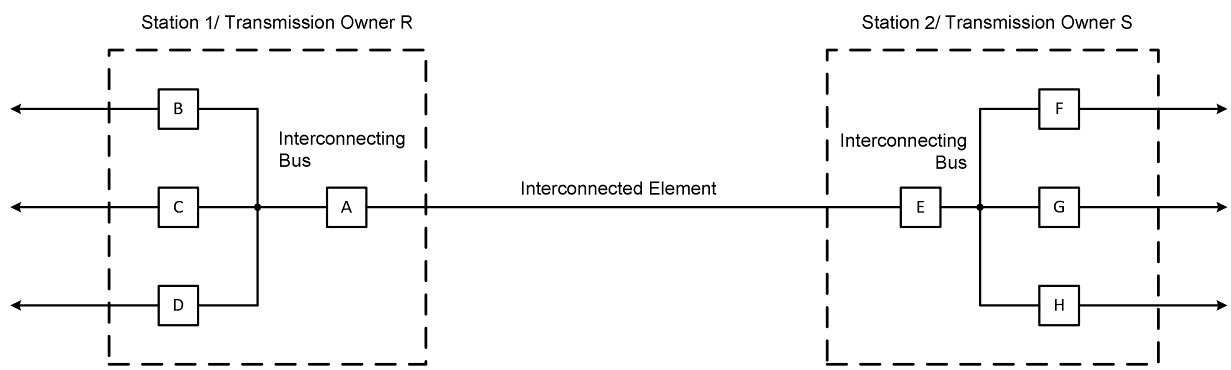
Diagrams

Introduction: The diagrams below are intended to provide guidance, to the owners of Facilities associated with the affected Interconnected Element, for meeting the requirements of this standard. These examples are not intended to be inclusive of all situations and are based on the assumption that entities employ the appropriate engineering expertise and due diligence in developing settings for their Protection Systems. The examples given also assume a single owner as the initiator of a Protection System Coordination Study (PSCS) for the applicable Interconnected Element. In actuality, any owner or owners may initiate the process. After the reviews of the PSCS or a summary of results, and prior to implementation of changes, the owners must work together to resolve any coordination issues identified during those reviews.

NOTES:

1. Protection System Coordination Studies are typically performed assuming maximum generation and all Facilities in service.
2. Protection Systems of the Transmission Owners, Generator Owners, and Distribution Providers described in the Figures and examples below do not include any systems or components enumerated in the 'Background Section' of this standard under "Other Aspects of Coordination of Protection Systems Addressed by Other Projects".

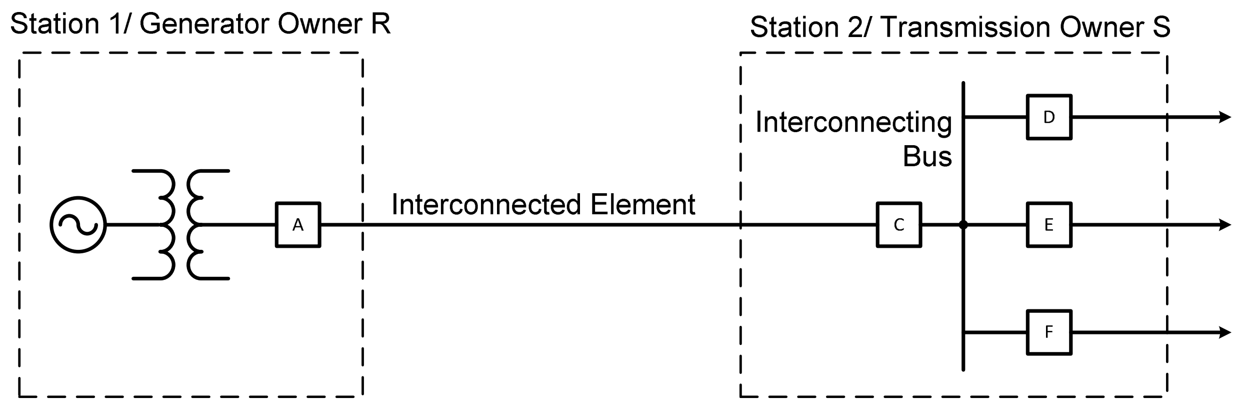
Figure 1



In Figure 1 above, the Interconnected Element between the Transmission Owners is the transmission line between Breakers A and E.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 1, Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers E, F, G, and H. Likewise, Owner S is to develop proposed Protection System settings associated with Breaker E. Owner R is to review the Protection System settings associated with Breaker E (provided by Owner S) for coordination issues with the Protection System settings associated with Breakers A, B, C, and D.

<u>Figure 2</u>

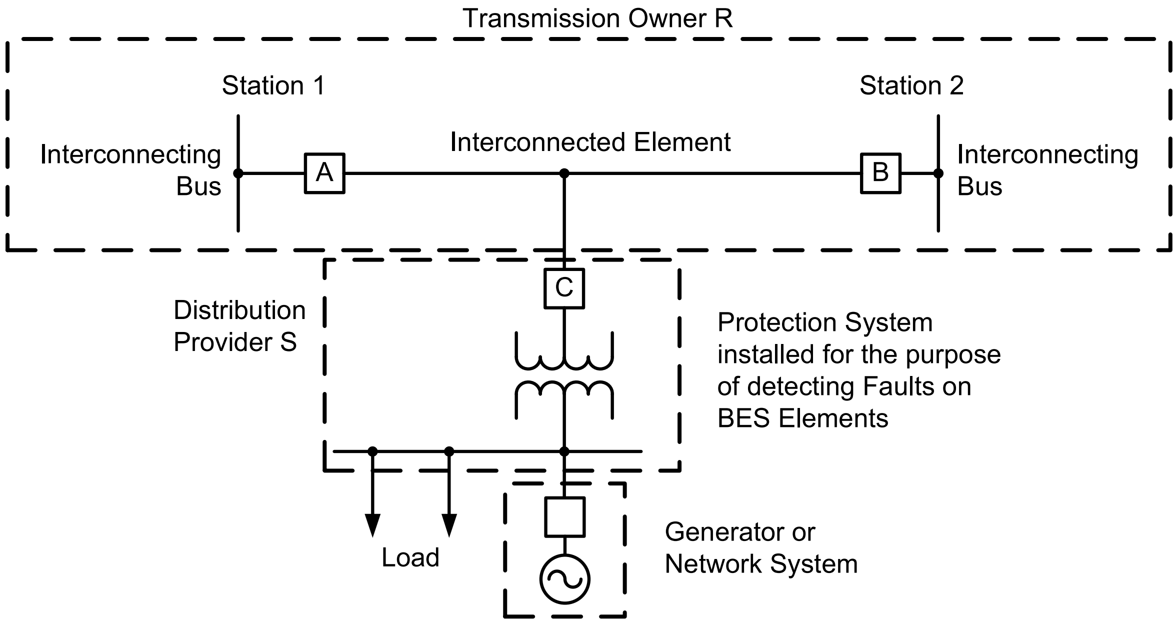


In Figure 2 above, the Interconnected Element between the Transmission Owner and the Generator Owner is the transmission line or bus between Breakers A and C.

Note: Depending on the actual configuration and/or ownership, Breaker A may, or may not, exist as a GSU unit high-side breaker or a line breaker.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 2, Owner R is to develop proposed Protection System settings associated with Breaker A. Transmission Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, Owner S is to develop proposed Protection System settings associated with Breaker C. Generation Owner R is to review the Protection System settings associated with Breaker C (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

Figure 3



In Figure 3 above, the Interconnected Element between the Transmission Owner and the Distribution Provider is the transmission line (or tap) between Breaker C and the point of connection to the line between Breakers A and B.

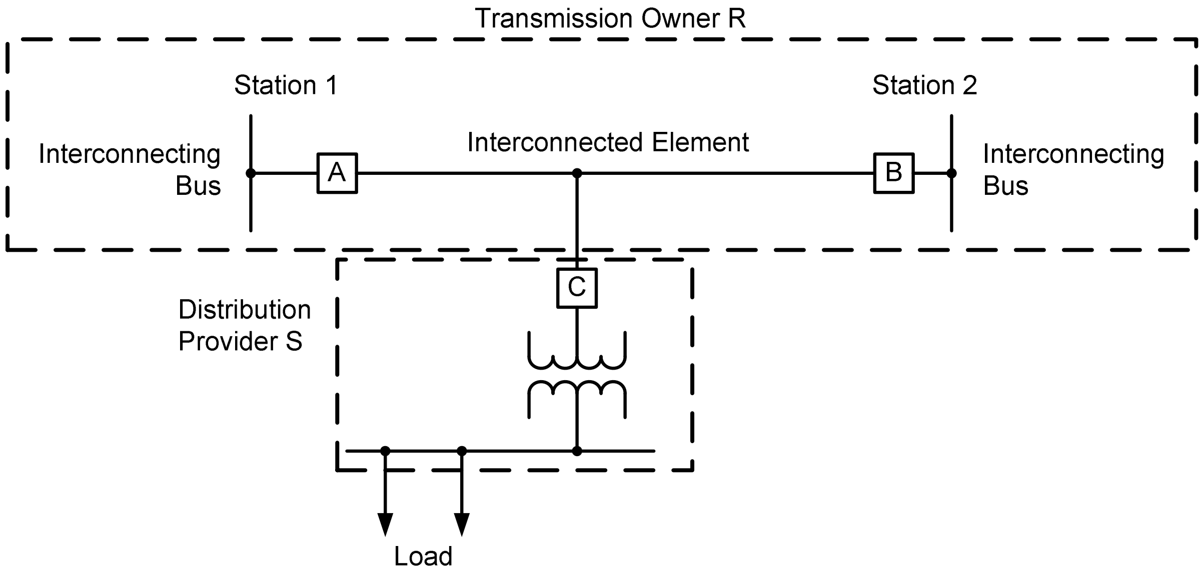
Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 3, Distribution Provider S is to develop proposed Protection System settings associated with Breaker C. Transmission Owner R is to review the Protection System settings associated with Line Breaker C (provided by Distribution Provider S) for coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2.

Notes:

A PSCS is required per this standard for this example if a Protection System at the Distribution Provider's substation is installed for the purpose of detecting Faults on BES Elements.

Protection Systems installed for the purpose of detecting Faults on BES Elements do not include relays that, though they may operate for such Faults, are not installed specifically for that purpose. As an example, reverse power relays are often installed to detect situations where the transmission source for a power transformer becomes de-energized (for whatever reason) while the distribution bank remains energized from a source on the low-voltage side. In this case, the settings of the reverse power relay are typically calculated based on the charging current of the transformer from the low-voltage side. Although relays installed and set in this manner may operate as a result of a Fault on a BES Element, they are not specifically installed for the purpose of detecting that Fault.

Figure 4



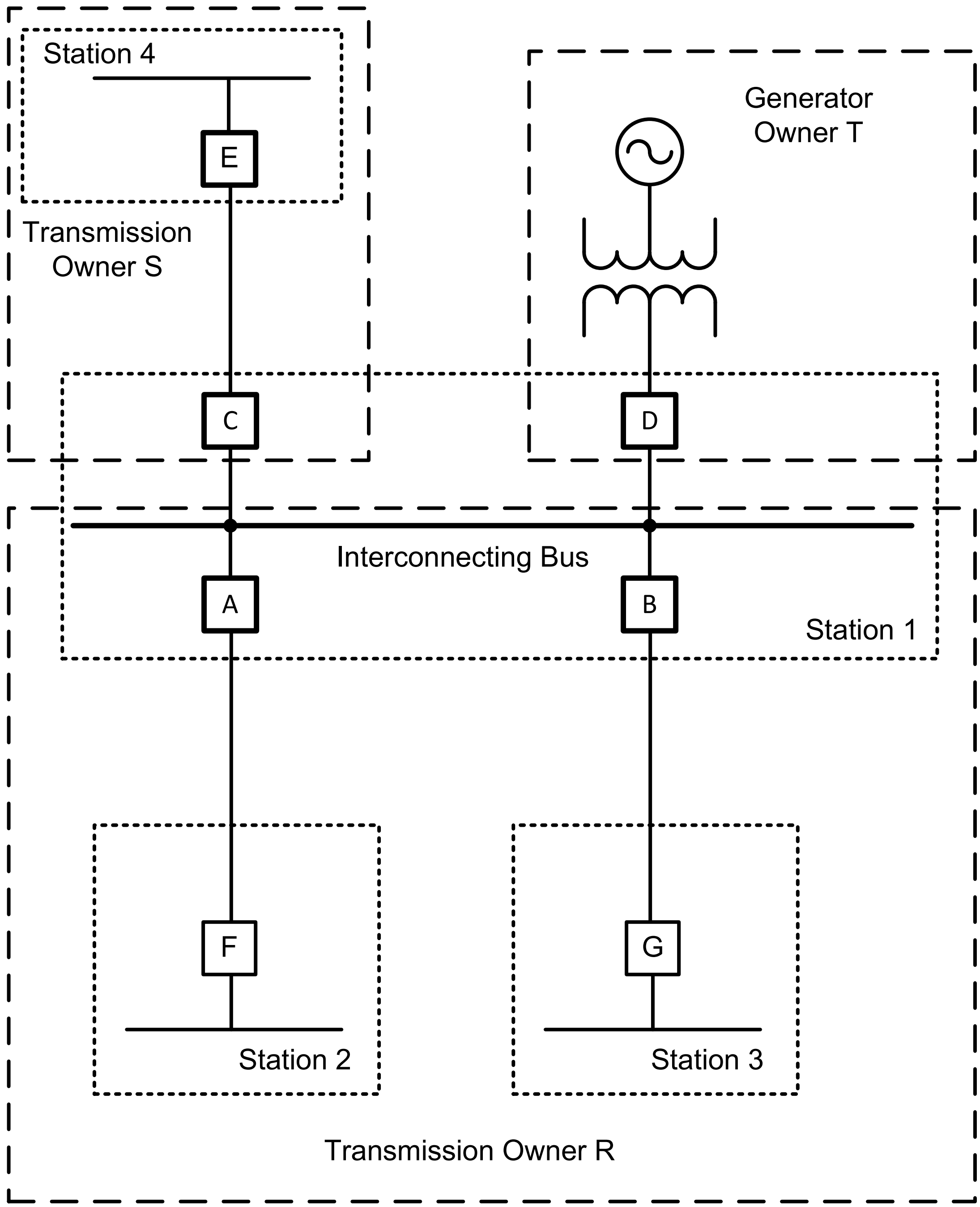
In Figure 4 above, the Interconnected Element between the Transmission Owner and the Distribution Provider is the transmission line or tap between the line and Breaker C.

Note: No specific PSCS is required per this standard for this example since the Protection System at the Distribution Provider's substation is not installed for the purpose of detecting Faults on BES Elements.

Figure 5

Transmission/Generation Facility with Multiple Owners

Note: In a large majority of cases, Figure 2 would be applicable for most generator interconnections. In Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T.



In Figure 5 above, the Interconnected Element between the Transmission Owners R and S and Generator Owner T is the common Transmission bus. In this example, Transmission Owner S and Generator Owner T are not directly interconnected to each other at Station 1. All direct interconnections are between Owner R and each of the other Owners connected to the common bus at Station 1.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 5:

Owner S is to develop proposed Protection System settings associated with Breakers C and E.

Owner T is to develop proposed Protection System settings associated with Breaker D, the generator, and its associated equipment.

Owner R is to develop proposed Protection System settings associated with Breakers A, B, F and G.

Owner R is to review the Protection System settings associated with Breaker C, E, D, and the generator Protection System (provided by Owners S and/or T) for coordination issues with the Protection System settings associated with Breakers A and B.

Owner S is to review the Protection System settings associated with Breakers A, F, B, G, D, and the generator Protection System (provided by Owners R and/or T) for coordination issues with the Protection System settings associated with Breaker C. To perform this review, it will be necessary that Transmission Owner R provide Owner S with its settings for Breakers A, F, B, and G, as well as the settings for Breaker D and generator Protection System settings provided to Owner R by Generator Owner T.

Owner T is to review the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R and/or S) for coordination issues with the Protection System settings associated with Breaker D or the generator Protection System. In order to perform this review, it will be necessary that Transmission Owner R provide Generator Owner T with its settings for Breakers A, F, G, and B, as well as the settings for Breaker C and E provided to Owner R by Transmission Owner S.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Draft 1 of SAR posted for comment June 11, 2007 – July 10, 2007.
2. SAR approved on August 13, 2007.
3. First posting of revised standard PRC-001-2 on September 11, 2009.
4. Transitioned from a revision of PRC-001-1 to development of PRC-027-1 based on industry comments, Quality Review feedback, and consideration of FERC directives relative to the existing requirements of PRC-001-1.
5. Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012.
~~5.~~6. Draft 2 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from November 16 – December 17, 2012.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPC SDT) created a new results-based standard, PRC-027-1, with the stated purpose 'to coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the ~~least number of power system Elements are isolated to clear~~desired sequence during Faults.'~~.~~ This standard incorporates and ~~enhances~~ clarifies the coordination aspects of Requirements ~~R3~~ R2 and ~~R4~~ R3 from PRC-001-~~1~~ 2 (~~now~~ formerly ~~R2~~ R3 and ~~R3~~ R4 of PRC-001-~~2~~1). The SPC SDT is requesting a posting for stakeholder comments ~~under~~ for a 30-day formal comment period with a parallel successive ballot.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period with Parallel Successive Ballot	~~November 2012~~June 2013
Conduct Recirculation Ballot	~~January~~August 2013
BOT Adoption	~~August~~November 2013

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is ~~six~~12 months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is ~~six~~12 months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. For Interconnected Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2007-06 – PRC-027-1	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here.

The following terms are defined for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

Interconnected Element: ~~An~~A BES Element that electrically joins facilities owned by:
a) separate ~~Functional~~Registered Entities, ~~including those Functional Entities that are a part of~~or
b) the same Registered Entity~~.~~ that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

Protection System Coordination Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Coordination for Performance During Faults**

2. **Number:** PRC-027-1

3. **Purpose:** To coordinate Protection Systems for Interconnected Elements, such that ~~the least number of power system Elements are isolated to clear~~Protection System components operate in the desired sequence during Faults.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider

~~**4.2 Facilities:**~~

4.2 Facilities: For the purpose of the requirements contained herein, the following Protection Systems owned by each Functional Entity in 4.1 above are those to which these requirements are applicable.

4.2.1 Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements

5. **Background:**

On December 7, 2006, the NERC Planning Committee approved the assessment of Reliability Standard PRC-001 – System Protection Coordination, prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF noted problems with the applicability to entities and vagueness of requirements in the existing PRC-001-1 reliability standard. The SPCTF concluded that the deficiencies of Reliability Standard PRC-001-1 were magnified by having requirements that addressed coordination of protection functions and capabilities in the operating and planning timeframes. Consequently, the SPCTF recommended that the requirements for the operating horizon and planning horizon be clearly delineated, and possibly divided into two standards.

The NERC Standards Committee approved a Standard Authorization Request that included the modifications noted by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC SDT) posted an initial draft of Reliability Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC SDT attempted to address all issues identified by the SPCTF assessment of PRC-001-1. The SPC SDT responded to the comments from the initial posting of PRC-001-2, and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC Quality Review (QR) in December 2010. Based on the results from the QR, and after informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to follow the SPCTF recommendation and focused their knowledge and expertise on developing a new results-based standard, concentrating on the reliability aspects (the coordination of new and existing protective systems in the planning horizon) associated with Requirements R3 and R4 of PRC-001-1. These aspects of coordination are incorporated and ~~enhanced~~ clarified in the proposed Reliability Standard PRC-027-1 – Protection System Coordination for Performance During Faults with the stated purpose:

> *"To coordinate Protection Systems for Interconnected Elements, such that ~~the least number of power system Elements are isolated to clear~~Protection System components operate in the desired sequence during Faults."*

Additionally, the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address "the appropriate use of time delays in relays," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination.

PRC-001-1 contained a non-specific training requirement (Requirement R1), three operating time frame requirements (Requirements R2, R5 and R6), and two planning requirements (Requirements R3 and R4). The SPC SDT transferred the responsibility of addressing the operating Requirements R2, R5, and R6 to the drafting team for Project 2007-03 Real-time Operations, charged with revising the TOP group of reliability standards. The Project 2007-03 drafting team retired Requirements R2, R5, and R6 of PRC-001-1 because they addressed data and data requirements that are now included in ~~the proposed~~ Reliability Standard TOP-003-2. The NERC Board of Trustees adopted Reliability Standards TOP-003-2 and PRC-001-2 on May 9, 2012.

The SPC SDT revised PRC-001-2. Revisions include the removal of Requirements R2 and R3 (formerly Requirements R3 and R4 of PRC-001-1). These two legacy requirements are being retired because the aspects of coordination they address are incorporated in the proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The SPCSDT believes the training aspects of Requirement R1 would be more appropriately addressed by the PER group of Reliability Standards. Consequently, the drafting team has recommended via the NERC Issues Database that the future drafting team charged with revising PER-005-1 incorporate the reliability objective of Requirement R1 into the revised standard. Until that occurs, Requirement R1 of PRC-001-2 must remain in the standard. In an effort to improve PRC-001-2 until it can be fully retired, the drafting team has provided a measure to accompany Requirement R1. The Applicability section was also updated to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)~~The SPC SDT is incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 in a new standard (as recommended by the SPCTF assessment), and focusing on the performance of Protection Systems during Faults. Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) will be retired upon appropriate regulatory approval of the proposed standards PRC-001-3 and PRC-027-1. The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard.~~

~~Additionally, the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address "the appropriate use of time delays in relays," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination.~~

Other Aspects of ~~c~~Coordination of Protection Systems ~~a~~Addressed by ~~o~~Other Projects:

Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects.

- Underfrequency Load shedding programs are addressed ~~by~~in PRC-006-1~~ (Project 2007-01 Underfrequency Load Shedding – pending FERC approval) and generator~~. Generator performance during frequency excursions is being addressed ~~by~~in PRC-024-1 ~~in~~by Project 2007-09 Generator Verification.
- Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed ~~by~~in PRC-024-1 ~~in~~by Project 2007-09, Generator Verification.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is being addressed ~~by~~in PRC-019-1 ~~in~~by Project 2007-09.
- Transmission relay loadability is addressed in PRC-023-~~1 and, pending FERC approval, PRC-023-~~2.
- Generator relay loadability will be addressed in PRC-025-1 by Phase 2 of Relay Loadability: Generation, in Project 2010-13.2.
- Protective relay response during power swings will be addressed ~~in~~by Phase 3 of Project 2010-13.3, Relay Loadability.
- Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and will be improved in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

The SPC SDT believes that including these other aspects of protection coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

B. Requirements and Measures

Rationale for R1:

Part 1.1 A Protection System Coordination Study (
for existing and new Interconnected Elements. Th
BES Element that electrically joins facilities owne
Entity that represents multiple functional entity res
Transmission Owner)."

Part 1.1.1 The drafting team believes 60 calendar r
PSCS required where no study exists. The drafting
Protection Systems associated with Interconnected

Part 1.1.2 The drafting team believes that 12 calen
the studies required when determining, or being no
interconnecting bus, where such conditions may w
required, e.g., when a line is protected by dual curr
dependent upon Fault current.

Part 1.1.3 The drafting team believes that entities r
of changes identified in Requirement R3, or to tech
believes the timeframe associated with the requirem
project's scope and schedule. Specifying a time fr
3.1 is unnecessary because notification of such a c
entity has the incentive to provide the identified in
The drafting team believes that six months is an ap
or to technically justify why no such study is need
Requirement R3 Part 3.3.

Part 1.2 The drafting team believes to properly ens
Interconnected Element(s), all entities need to shar
The drafting team believes that 90 calendar days is
performed in accordance with Requirement R1, Pa
with the Interconnected Element(s).

Note: In cases where a single group performs an o
single document that provides the requirements for
by both Registered Entities.

~~Rationale for R1:~~

~~Part 1.1 Protection System Studies are necessary to verify coordination of Protection Systems for existing and new Interconnected Element. The drafting team defines the term "Interconnected Element" as "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity."~~

~~Part 1.1.1 The drafting team believes 48 months is an appropriate period of time for entities to perform the Protection System Studies required where no study exists. The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame.~~

~~Part 1.1.2 The drafting team believes that 6 months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater Fault current deviation at an interconnecting bus, where such conditions may warrant a new Protection System Study, or to technically justify why no such study is required, i.e., when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current.~~

~~Part 1.1.3 The drafting team believes that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, or to technically justify why no such study is needed. The drafting team believes the timeframe associated with this requirement is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3 is unnecessary because notification of such a change may occur weeks or years prior to the change. The initiating entity has the incentive to provide the identified information as soon as possible to ensure timely implementations.~~

~~Part 1.2 The drafting team believes to properly ensure coordination of Protection Systems associated with Interconnected Element(s), all entities need to share the summary of results of a Protection System Study (PSS) and assess the study results. The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSS performed in accordance with Requirement R1 to the owner(s) of the Protection System(s) associated with the Interconnected Element(s).~~

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

1.1. Perform a Protection System Coordination Study (PSCS) for each of its Interconnected ~~Element on its System~~Elements as follows:

1.1.1 Within ~~48~~60 calendar months after the effective date of this standard, if no ~~Protection System Study~~PSCS for that Interconnected Element exists.

1.1.2 Within ~~six~~12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required.

1.1.3 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1~~ or Part 3.3,~~, or within six calendar months of being notified of a change as described in Requirement R3, Part 3.3; or technically justify why such a study is not required.

1.2. Within 90 calendar days after the completion of each ~~Protection System Study~~PSCS, provide to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s~~)~~), a summary of the results of each ~~Protection System Study~~PSCS performed pursuant to ~~this requirement~~Requirement R1, Part 1.1, (including, at a minimum, the ~~protective relay settings~~Protection Systems reviewed, ~~power system Elements to be isolated, contingencies evaluated,~~the associated Fault currents used, any issues identified, and any revisions or actions proposed).

M1. Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1. and 1.1.2, and 1.1.3 is a dated ~~Protection System Study~~PSCS, or the summary results of each ~~Protection System Study (either in~~ PSCS (hard copy or electronic file formats) demonstrating ~~that~~ the time frames specified or agreed to in Parts 1.1.1~~ and,~~ 1.1.2~~.~~, and 1.1.3 were achieved. Acceptable evidence of a technical justification for not performing a ~~Protection System Study~~PSCS as specified in Parts 1.1.2 and 1.1.3 ~~could be~~may include, but is not limited to, documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any aspects of coordination.

M2. Acceptable evidence for Requirement R1, Part 1.2 is dated documentation demonstrating that the summary results of each ~~Protection System Study~~PSCS (hard copy or electronic file formats) ~~was~~were provided within the specified time frame to the owner(s) of the Protection System(s) associated with the Interconnected Element(s).

Rationale for R2: This requires a periodic review of Fault currents at the interconnecting bus and providing ~~to~~ the results to the applicable entities when ~~deviations~~changes occur that meet the criteria of Requirement R2 ~~criteria~~. It is important that interconnected Facility owners are kept aware of changes that could affect proper performance of their Protection Systems. The Transmission Owner is identified as the entity responsible for performing the short circuit studies because they maintain the data necessary to perform the studies. ~~The drafting team determined that 10% was an appropriate point to provide this information based on the fact that Protection Systems are typically set with margins above 10%.~~Note: short circuit studies are used to determine the Fault current values at the interconnecting bus where a PSCS exists. These studies are typically performed assuming maximum generation and all Facilities in service.

~~Part 2.1 Short circuit databases are customarily updated annually, so the~~The drafting team believes ~~24~~60 calendar months provides the entities flexibility to either technically justify why Fault current does not affect the Protection System coordination, or schedule and perform the ~~new~~ activities specified in Requirement R2, Parts 2.1 and 2.2.

The drafting team recognizes the coordination of some types of Protection Systems is unaffected by changes in Fault current and, where technically justified, can be exempted from the short circuit ~~studies and calculate the percent deviation.~~ review.

Part 2.1 The drafting team believes ~~studies associated with changes that would affect~~maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus are necessary quantities needed to review the coordination ~~in less time would be triggered by other requirements in this standard.~~.

Part 2.2 The drafting team is including this ~~formula~~equation to assure a consistent approach is used by each Transmission Owner when calculating the percent ~~deviation~~change in Fault current values.

R2. For each ~~Facility associated with an~~ Interconnected Element on its System, the Transmission Owner shall, once every 60 calendar months, technically justify why Fault current does not affect the Protection System coordination, or: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

~~**2.1.** At least once every 24 months:~~

~~2.2.~~2.1. Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Coordination Study (PSCS) is available per Requirement R1.

~~2.3.~~2.2. Calculate the percent ~~deviation~~change between the Fault current values (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent ~~Protection System Study~~PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.~~1~~.1, using the following equation:

$$\%\ \cancel{Deviation}Change = \cancel{\left|\frac{Iscs - Ipss}{Ipss}\right|}\left|\frac{Iscs - Ipscs}{Ipscs}\right| x\ 100$$

Where: I_{scs} = Fault current value from present short circuit study

And: I_{pscs} = Fault current value used in the most recent ~~Protection System Study~~PSCS

2.2.1 Within 30 calendar days after identification ~~where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates~~of a ~~deviation in Fault current~~change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (I_{scs}) to each owner of the Protection System associated with the Interconnected Element ~~the updated Fault current values (I_{scs}).~~.

M3. Acceptable evidence of technical justification for not performing a short circuit study as specified in Requirement R2, could be documented engineering analyses or assessments that demonstrate why Fault current does not impact any aspects of coordination.

~~**M3.**~~**M4.** Acceptable evidence for Requirement R2, ~~Part~~ Parts 2.1 and 2.2~~.1~~ is dated documentation (hard copy or electronic file formats) that contains the present Fault current values from the short circuit study for each interconnecting bus analyzed, and ~~that~~ identifies the percent ~~deviation~~change from the ~~most recent Protection System Study~~ Fault current values used in the most recent PSCS determined by the ~~formula~~equation.

~~**M4.**~~**M5.** Acceptable evidence ~~that the updated Fault current values (I_{scs}), along with~~for Requirement R2, Part 2.2.1 is dated documentation (hard copy or electronic file formats) ~~for Requirement R2, Part 2.2 was~~that the updated Fault current values (I_{scs}), were provided within the specified timeframe to each owner of the Protection System associated with the Interconnected Element.

Rationale for R3: This requires the transfer of appropriate information to the entities associated with each Interconnected Element due to circumstances identified in Parts 3.1, 3.2, and 3.3.

Part 3.1 The reliability objective of this requirement is to enable the process of conducting PSCSs by ensuring that the information is provided to the owner(s) of the Protection Systems associated with Interconnected Element(s). The drafting team believes that information about any proposed change or addition (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the Interconnected Element. The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list provided in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. Examples of changes to generator units that result in impedance changes could include replacements and re-ratings. This requirement also pertains to changes identified as a result of studies performed in Requirement 1, Part 1.1.

Part 3.2 The purpose of this requirement is to provide a means for an entity to receive the requested information in a timely manner in order to perform a PSCS, as required in R… believes 30 calendar days after receipt of the request is a su… requirement also provides some flexibility for the parties in… appropriate.

Part 3.3 The drafting team believes 30 calendar days is suffi…

~~Rationale for R3: This requires the transfer of appropriate information to the entities associated with each Interconnected Element due to circumstances identified in Parts 3.1, 3.2, and 3.3.~~

~~Part 3.1 The reliability objective of this requirement is to enable the process of conducting Protection System Studies by ensuring that the information is provided to the owner(s) of the Protection Systems associated with Interconnected Element(s). The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. Examples of changes to generator units that result in impedance changes could include replacements and re-ratings. This requirement also pertains to changes identified as a result of studies performed in Part 1.1.~~

~~Part 3.2 The purpose of this requirement is to provide a means for an entity to receive the requested information in a timely manner in order to perform a Protection System Study, as required in Parts 1.1.1, 1.1.2, and 1.1.3. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide this information. The requirement also provides some flexibility for the parties involved to determine an otherwise agreed-to schedule, if appropriate.~~

~~Part 3.3 The drafting team believes 30 calendar days is sufficient time to provide the information.~~

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnected Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

3.1. Details for any proposed change or addition~~s~~ listed below; either at an existing or new Facility associated with the

Interconnected Element; or at other ~~f~~Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).

- New installation, replacement with different types, or modification of ~~:~~ protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios
- Changes to a transmission system Element that ~~change~~alter any sequence or mutual coupling impedance
- Changes to generator unit(s) that result in a change in impedance
- Changes to the generator step-up transformer(s) that result in a change in impedance

3.2. Requested information related to the coordination of Protection Systems associated with an Interconnected Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule.

3.3. Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.

~~M5.~~M6. Acceptable evidence for Requirement R3, Part 3.1 may include, but is not limited~~,~~ to, documentation (hard copy or electronic file formats) demonstrating that a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) ~~in hard copy or electronic file formats~~ as identified in the bulleted list ~~for Requirement R3, Part 3.1,~~ was provided to each responsible entity connected to the same Interconnected Element.

~~M6.~~M7. Acceptable evidence for Requirement R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was provided according to the agreed-upon schedule, or within 30 calendar days absent such an agreement.

~~M7.~~M8. Acceptable evidence for Requirement R3, Part 3.3 is dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the changes made was provided within 30 calendar days.

Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with Interconnected Elements affirm that the Protection System(s) applied are acceptable per the conditions identified in Parts 4.1 and 4.2.

Part 4.1 The drafting team believes 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with Interconnected Elements to review the summary results of a PSCS and respond. Note: Per Requirement R1, Part 1.2, at a minimum, the summary results of a PSCS must include the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. The response should indicate acceptance with the review results/conclusions; or rejection of or disagreement with the review results/conclusions and offer of suggestions/modifications to resolve any identified coordination issues. The drafting team recognizes there could be situations where one owner may not agree with the other owner's protection philosophy but they accept the proposed changes since no coordination issues were identified.

Part 4.2 The drafting team believes that proposed changes or modifications (including project schedules) to Facilities associated with the Interconnected Element, as described in Requirement R3, Part 3.1, or modifications suggested in Requirement R4, Part 4.1 must be communicated and accepted prior to the in-service date. Acceptance assures that the coordination of Protection Systems associated with the affected Interconnected Element is achieved.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

> ~~Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with Interconnected Elements confirm that the Protection System(s) applied are acceptable per the conditions identified in Parts 4.1 and 4.2.~~
>
> ~~Part 4.1 The drafting team believes 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with Interconnected Elements to review the summary results of a Protection System Study. If any issues are identified that require changes then respond whether further action is required.~~
>
> ~~Part 4.2 The drafting team believes that proposed modifications (including project schedules) to Facility changes associated with the Interconnected Element, as described in Requirement R3, Part 3.1, must be communicated and accepted prior to the in-service date. Acceptance assures that the coordination of Protection Systems associated with the affected Interconnected Element is achieved.~~

4.1. Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a ~~Protection System Study, as described in~~PSCS (per Requirement R1, Part 1.2~~,~~) and respond ~~as~~ to ~~whether further action is required.~~ the other owner(s):

- Accepting the results, or
- Rejecting the results and suggesting modifications to resolve any identified coordination issues.

4.2. Prior to implementing any ~~planned~~proposed change(s) or modifications associated with Requirement R3, Part 3.1~~, confirm the~~ or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element ~~accept any resulting~~have accepted the Protection System(s) changes including the resolution of any identified coordination issues.

~~M8.~~**M9.** Acceptable evidence for Requirement R4, Part 4.1 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement.

~~M9.~~**M10.** Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that ~~confirmation of acceptance was achieved,~~ prior to implementation of any ~~planned~~proposed Protection System(s) changes or modifications, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System ~~at~~associated with an Interconnected ~~Facility~~Element shall each keep data or evidence to show compliance with Requirements R1, R2, R3, and R4, and Measures M1 through ~~M9~~M10, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner ~~and~~or Distribution Provider that owns a Protection System at a Facility associated with an Interconnected Element is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity performed a Protection System Coordination Study on an Interconnected Element ~~per~~as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus ~~per~~as required in Requirement R1, Part 1.1.2, or ~~documented~~technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided the Protection	The responsible entity performed a Protection System Coordination Study on an Interconnected Element ~~per~~as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days~~.~~ but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus ~~per~~as required in Requirement R1, Part 1.1.2, or ~~documented~~technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to ~~40~~45 calendar days. OR The responsible entity	The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus ~~per~~as required in Requirement R1, Part 1.1.2, or ~~documented~~technically justified why a study was not required, but was late by more than ~~40~~45 calendar days but less than or equal to ~~50~~60 calendar days. OR The responsible entity	The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus ~~per~~as required in Requirement R1, Part 1.1.2, or ~~documented~~technically justified why a study was not required but was late by more than ~~50~~60 calendar days. OR The responsible entity provided the Protection

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by less than or equal to 10 calendar days ~~or less~~.	provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar days. OR The responsible entity failed to perform a Protection System Coordination Study on an Interconnected Element ~~per~~in accordance with Requirement R1, Parts 1.1.1, 1.1.2, or 1.1.3~~, or document~~. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2 or 1.1.3. OR The responsible entity failed to provide Protection System Coordination Study results in accordance with Requirement R1,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Part 1.2.
R2	Long-term Planning	Medium	For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by less than or equal to 30 calendar days. OR The Transmission Owner performed a short circuit study, as ~~described~~required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days.	For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The Transmission Owner performed a short circuit study as ~~described~~required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to ~~40~~60 calendar days.	For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The Transmission Owner performed a short circuit study as ~~described~~required in Requirement R2, Part 2.1, but was late by more than ~~40~~60 calendar days but less than or equal to ~~50~~90 calendar days.	~~The~~ For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 90 calendar days. OR The Transmission Owner performed a short circuit study as ~~described~~required in Requirement R2, Part 2.1, but was late by more than ~~50~~90 calendar days. OR The Transmission Owner failed to perform a short circuit study, as ~~described~~required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as ~~described~~required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as ~~described~~required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as ~~described~~required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	percent ~~deviation~~change between the Fault currents, according to the ~~formula~~equation designated in Requirement R2, Part 2.~~1~~2. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as ~~described~~required in Requirement R2, Part 2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnected Element, the ~~changes in~~updated Fault ~~currents~~current values, as required in Requirement R2, Part 2.2.1.
R3	Operations Planning	Medium				The responsible entity failed to provide ~~information to~~ the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The responsible entity provided the requested information ~~per~~required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days ~~or less~~. OR The responsible entity provided the ~~required~~ information ~~identified~~required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days ~~or less~~.	The responsible entity provided the requested information ~~per~~required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the ~~required~~ information ~~identified~~required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information ~~per~~required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the ~~required~~ information ~~identified~~required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	owner(s) of the Facility associated with the Interconnected Element, details for any proposed change or addition identified in Requirement R3, Part 3.1. OR The responsible entity provided the requested information ~~per~~required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the ~~required~~ information ~~identified~~required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the ~~requested~~ information required in Requirement R3, Part 3.3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The responsible entity ~~confirmed acceptance~~responded in more than 90 calendar days but less than or equal to 100 calendar days following the receipt of the summary results of the Protection System Coordination Study ~~per~~, as required in Requirement R4, Part 4.1~~, but was late by 10 calendar days or less~~.	The responsible entity ~~confirmed acceptance~~responded in more than 100 calendar days but less than or equal to 110 calendar days following the receipt of the summary results of the Protection System Coordination Study ~~per~~, as required in Requirement R4, Part 4.1~~, but was late by more than 10 calendar days but less than or equal to 20 calendar days~~.	The responsible entity ~~confirmed acceptance~~responded in more than 110 calendar days but less than or equal to 120 calendar days following the receipt of the summary results of the Protection System Coordination Study ~~per~~, as required in Requirement R4, Part 4.1~~, but was late by more than 20 calendar days but less than or equal to 30 calendar days~~.	The responsible entity ~~confirmed acceptance~~responded in more than 120 calendar days following the receipt of the summary results of the Protection System Coordination Study ~~per~~, as required in Requirement R4, Part 4.1~~, but was late by more than 30 calendar days.~~. OR The responsible entity failed to ~~confirm acceptance of~~review the summary results of the Protection System Coordination Study ~~per~~provided to them in accordance with Requirement R4, Part 4.1. OR The responsible entity failed to ~~confirm acceptance of the planned~~respond to the other owners in accordance with Requirement R4, Part

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						4.1. OR The responsible entity failed to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element accepted the Protection System(s) changes ~~pursuant to R4, Part 4.2~~including the resolution of any identified coordination issues, prior to implementation of those changes, as required in Requirement R4, Part 4.2.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Purpose:

To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.

This standard requires that separate Registered Entities communicate with each other to coordinate Protection System components on existing Interconnected Elements; and communicate with each other prior to the energization of new or modified Protection Systems associated with Interconnected Elements. The goal of the coordination is to verify that the Protection Systems intended for sensing Faults will operate in the desired sequence for internal and external Faults on the Interconnected Element.

Requirement R1:

This requirement directs the ~~performance of~~applicable entities to perform a Protection System ~~Studies~~Coordination Study (PSCS) for every Interconnected Element to verify coordination of existing Protection Systems where no recent study exists; or when Facility configuration changes are made, or where Fault current ~~deviations~~changes of 10% or more have occurred. In developing the language to define ~~Protection System Study~~a PSCS, the System Protection Coordination Standard Drafting Team (~~SPC SDT~~SPC SDT) considered various reference books discussing protective relaying theory and application, along with the following description of "coordination of protection" from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Using the reference material cited above as guidance, the drafting team defined the term Protection System Coordination Study (PSCS) for use within the PRC-027-1 Reliability Standard as:

> "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults."

~~Protection System Studies~~PSCSs comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in ~~Protection System Studies~~PSCSs include maximum generation with the transmission system under normal operating conditions and under single contingency conditions. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), and adequate directional polarizing quantities.

The drafting team believes applicable entities should have a documented ~~Protection System Study~~PSCS for each Interconnected Element to validate the Protection Systems associated with those Interconnected Elements perform in a manner consistent with the purpose of this Standard. Additionally, the drafting team believes that ~~48~~60 calendar months is an appropriate amount of time for entities to perform the initial studies expected under this requirement. This period considers the time some entities may require to create project scopes, acquire proposals, and secure contracts to hire external resources that may be needed to perform the studies. The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with Interconnected Elements that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.

Parts 1.1.2 and 1.1.3 further direct that ~~Protection System Studies~~PSCSs must be completed under the following two circumstances:

1. After notification of an identified 10% or greater ~~deviation~~change in Fault current~~,~~ (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1), the notified entities must perform a new ~~Protection System Study~~PSCS of the Interconnected Element or document why a study is not required. The drafting team recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater ~~deviation~~change in Fault current may not necessitate a new ~~Protection System Study~~PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the ~~six~~ 12-calendar month time frame associated with this requirement represents a reasonable period to perform the studies that are required after identification by the ~~24~~ 60-calendar month Fault current review.

2. After proposing or being notified of a change at a Facility associated with the Interconnected Element, entities must perform a new ~~Protection System Study~~PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the proposed or notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new ~~Protection System Study~~PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the timeframe associated with ~~this requirement~~performing a PSCS for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3, Part 3.1 is unnecessary because notification of such a change may occur weeks or years prior to the change due to the wide variety of

conditions that may be associated with a particular change. The drafting team sees the entity initiating any change as having the incentive to move this along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2. The drafting team believes that six calendar months is an appropriate period of time for entities to perform the studies required, or to technically justify why no such study is needed, when details of changes are provided associated with Requirement R3 Part 3.3.

Requirement R1, Part 1.2 directs the entity performing the ~~Protection System Study~~PSCS to provide a summary of the study results to the affected Interconnected Element owner(s). The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS it performed to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s). (Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that meets the requirements for a summary of the results of the PSCS would be sufficient for use by both Registered Entities.) As guidance, the drafting team lists the following inputs and results of a ~~Protection System Study~~PSCS that may be included in the summary provided pursuant to this requirement:

1. A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Facility, and which were reviewed for coordination of protective relays as part of the study, including the contingencies used in the evaluation.
2. ~~Data used to determine Fault currents in performing the study, along with a~~A listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Facility under study.
3. A listing of any issues associated with the relay settings of the other owner(s) at the Facility that were identified by the study.
4. Any proposed revisions to a Protection System or its protective relay settings that were identified by the study.

Requirement R2:

The drafting team investigated various inputs that would trigger a review of the existing ~~Protection System Studies~~PSCSs and determined, through the experience of the drafting team members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated ~~Protection System Study~~PSCS may be necessary. These variations could result from the accumulation of incremental changes over time. This requirement mandates the Transmission Owner either provide a technical justification stating why Fault current does not affect the Protection System coordination of a specific Interconnected Element or perform a periodic review of Fault currents.

Examples of Protection Systems where technical justifications may be used include:

1. Differential elements
2. Distance elements where infeed is not used in determining reach for the protection scheme.
3. Supervised overcurrent elements enabled by:
    - Loss of potential condition
    - Some communication assisted tripping
    - Switch-Onto-Fault (SOTF)
4. Reverse power, definite time &/or time overcurrent elements:
    - Designed to coordinate during maximum generation with the transmission system under normal operating conditions and ~~includes the calculation of the percent deviation between the~~ under single contingency conditions regardless of Fault current.
    - Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.).

The short circuit study provides the Fault current values used ~~in the~~ to calculate the percent change between the most recent ~~Protection System Study~~PSCS and the present Fault current values indicated by the short circuit study performed pursuant to ~~this requirement~~Requirement R2, Part 2.1. This calculation is necessary to identify Fault current changes that must be communicated in accordance with Requirement R2, Part 2.2. Short circuit studies are typically performed assuming maximum generation and all Facilities in service.

~~Polling of~~The drafting team ~~membership and various protection engineering committees indicates~~believes that ~~short circuit databases are customarily updated annually. Based on this information, the drafting team believes that requiring a 24-month periodic review of~~60 calendar months is an appropriate interval for technically justifying why Fault currents ~~provides entities additional flexibility to schedule and perform these studies and calculate the percent deviation, as described in Requirement R2, Part 2.1.~~ do not affect the Protection System coordination of a specific Interconnected Element, or for reviewing Fault currents. The drafting team believes studies associated with changes that would affect the coordination in less than ~~24~~60 calendar months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.2.1 further directs the Transmission Owner to, within 30 calendar days, inform each owner of the Facility associated with the Interconnected Element when short circuit studies indicate that 10% ~~deviations~~changes in Fault current have occurred at the interconnecting bus(s). The drafting team believes the 30-calendar day time frame associated with this requirement is reasonable for providing the Fault current information to the interconnected entity(s) and is consistent with other NERC reliability standards.

In Requirement R2, the Transmission Owner is identified as the ~~Functional Entity~~functional entity responsible for performing the ~~Fault current~~short circuit studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.

Requirement R3:

This directs the registered functional entity initiating any proposed change or addition to provide the details to the other affected entities of the Interconnected Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes. Documentation provided to these other owners may include, but is not limited to, power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings. The recipient will incorporate the applicable information into its ~~Protection System Studies~~PSCSs to evaluate whether changes are required.

The list of applicable changes provided in Requirement R3, Part 3.1 is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. The drafting team recognizes that Facility changes at other locations can impact the ~~Protection System Study~~PSCS of the Facility associated with the Interconnected Element; e.g., the addition of a large autotransformer bank or generator not directly ~~associated with~~connected to the Interconnected Element. The drafting team believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the drafting team sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2.

Requirement R3, Part 3.2 allows for entities to agree upon a schedule, appropriate to the circumstances, for providing the details needed to conduct a ~~Protection System Study~~PSCS or, absent such agreement, within 30 calendar days of a request for this information. This requirement provides a means for entities to receive requested information in a timely manner. In consideration of circumstances where the information may not be readily available or may be incomplete due the retirement of personnel, the purging of records, change of ownership, etc., it also provides the flexibility of mutually agreeing to a schedule for exchanging information. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide the requested information where no other agreement exists.

Additionally, this requirement includes a provision for providing details associated with changes to the previously agreed-upon coordination when changes are made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components Based upon the limited number of instances that would occur under such circumstances, the drafting team believes 30 calendar days after determining that changes are required is an appropriate time frame for providing the associated details to affected entities.

Requirement R4:

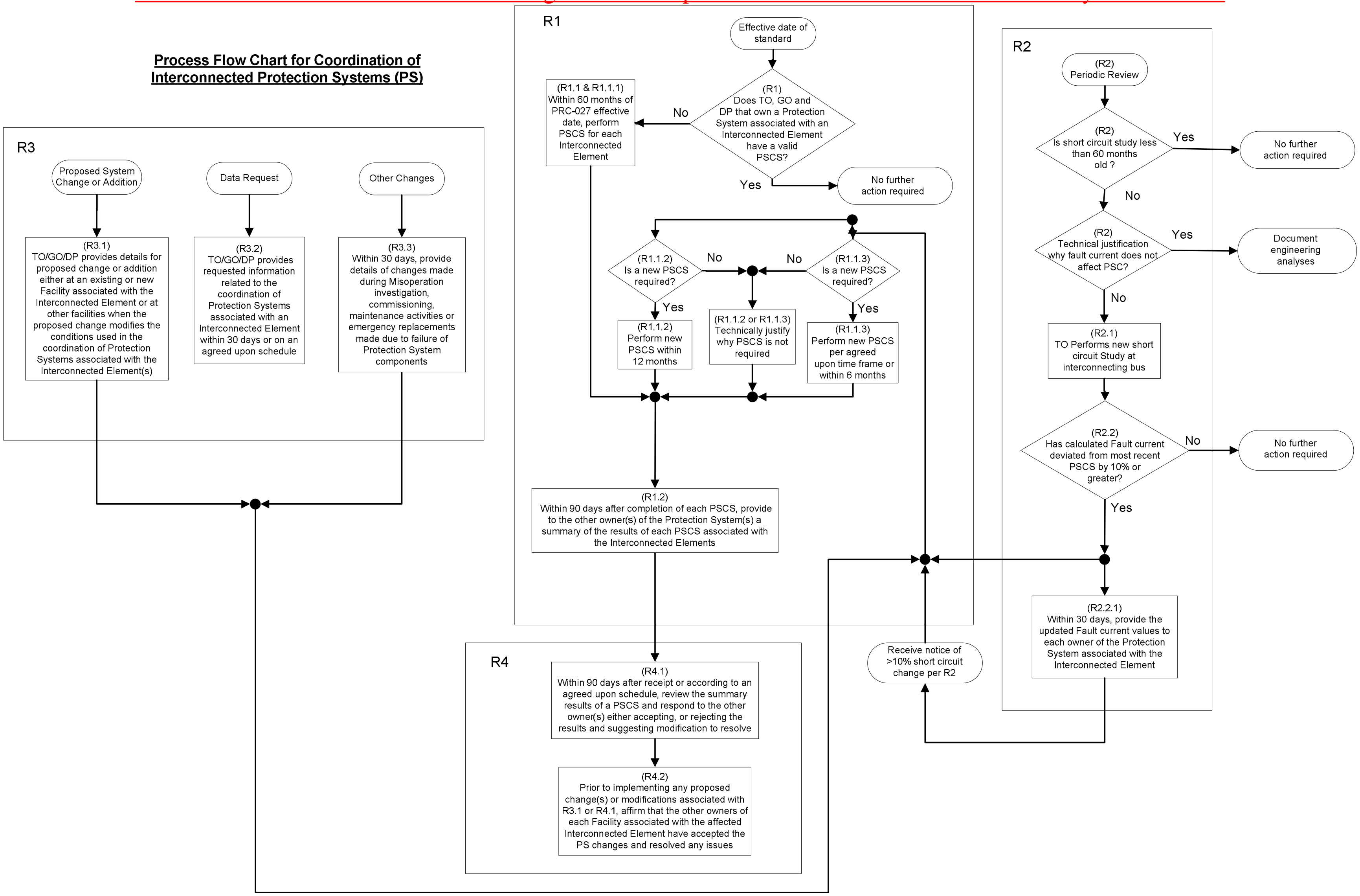
The reliability objective of this requirement is to bring the process of Protection System coordination full circle by gaining the confirmation of interconnected entities that their Protection Systems are coordinated consistent with the purpose of this standard. Cooperative participation of Facility owners in communicating Protection System(s) design, and study results will achieve coordination of Protection Systems for reliable operation of the BES during Faults.

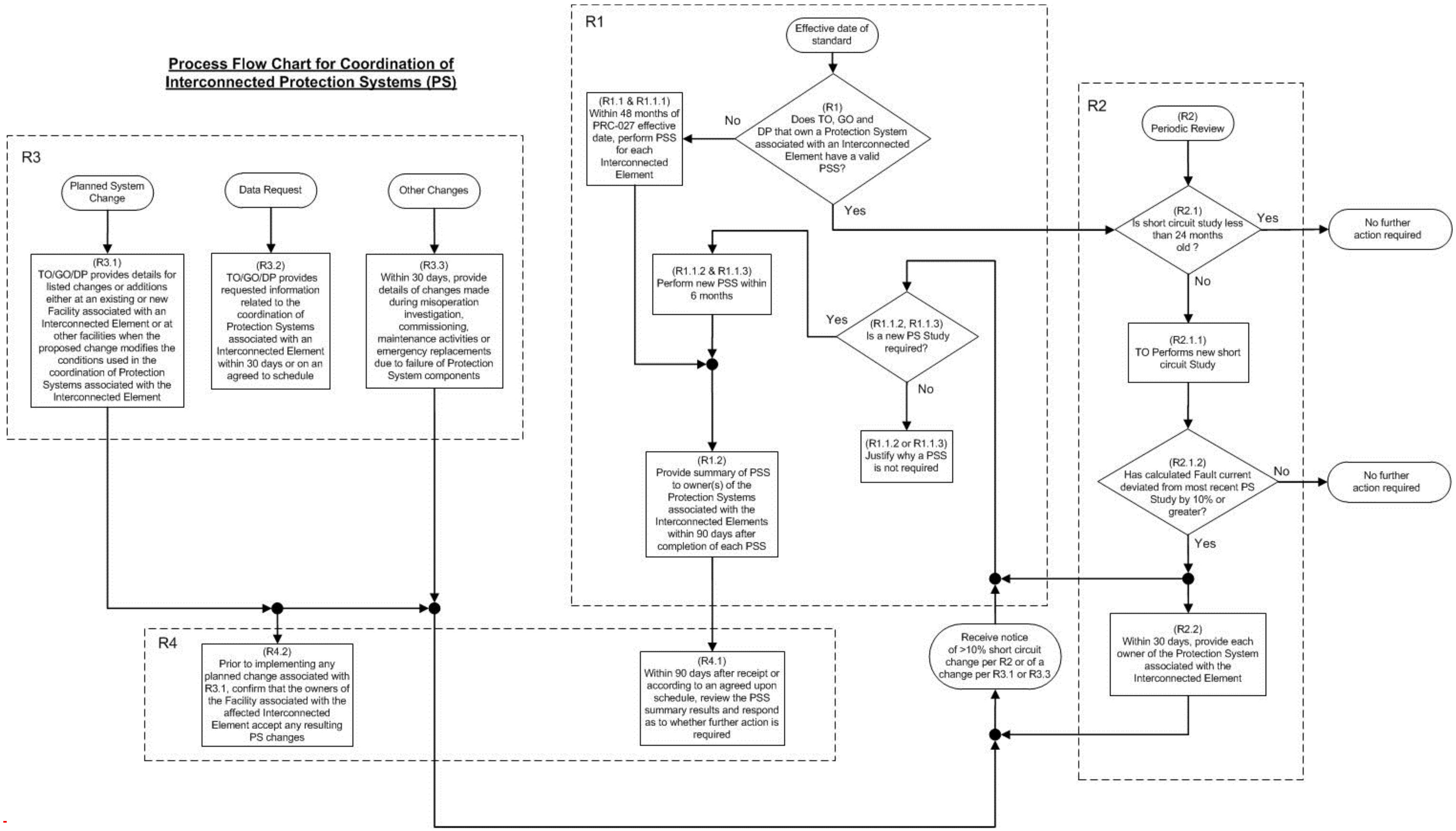
Requirement R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to review the summary results of a ~~Protection System Study~~PSCS, as described in Requirement R1, Part 1.2; ~~or absent acceptance propose revisions~~and respond as to ~~achieve acceptable results.~~whether they accepting or rejecting the results, and if rejecting, suggesting modifications to resolve any identified coordination issues. The drafting team believes 90 calendar days after receipt of the results of a ~~Protection System Study~~PSCS provides a reasonable time for the owners of Facilities to ~~resolve differences and confirm acceptance that their Protection Systems are coordinated~~review the summary results of a PSCS.

Requirement R4, Part 4.2 directs entities to ~~con~~affirm that ~~planned~~the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes as described in Requirement 3, Part 3.1 ~~are acceptable~~and Requirement 4, Part 4.1 prior to the in-service date of those changes. Any coordination issues identified during the review must be resolved prior to implementing the proposed changes. The purpose of ~~this requirement~~Requirement 4, Part 4.2 is to assure the effects ~~that planned~~the proposed changes have on Protection Systems at a Facility associated with the ~~affected~~ Interconnected Element have been considered by all affected entities.

Process Flow Chart: Below is a complete representation of the process, including the relationships between requirements:

Note: All timeframes referenced in the diagram below represent "calendar month" or "calendar day" timeframes.




Process Flow Chart for Coordination of Interconnected Protection Systems (PS)
R1
Effective date of standard
(R1) Does TO, GO and DP that own a Protection System associated with an Interconnected Element have a valid PSS?
No
(R1.1 & R1.1.1) Within 48 months of PRC-027 effective date, perform PSS for each Interconnected Element
Yes
(R1.1.2 & R1.1.3) Perform new PSS within 6 months
Yes
(R1.1.2, R1.1.3) Is a new PS Study required?
No
(R1.1.2 or R1.1.3) Justify why a PSS is not required
(R1.2) Provide summary of PSS to owner(s) of the Protection Systems associated with the Interconnected Elements within 90 days after completion of each PSS
R2
(R2) Periodic Review
(R2.1) Is short circuit study less than 24 months old ?
Yes
No further action required
No
(R2.1.1) TO Performs new short circuit Study
(R2.1.2) Has calculated Fault current deviated from most recent PS Study by 10% or greater?
No
No further action required
Yes
(R2.2) Within 30 days, provide each owner of the Protection System associated with the Interconnected Element
Receive notice of >10% short circuit change per R2 or of a change per R3.1 or R3.3
R3
Planned System Change
Data Request
Other Changes
(R3.1) TO/GO/DP provides details for listed changes or additions either at an existing or new Facility associated with an Interconnected Element or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element
(R3.2) TO/GO/DP provides requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 days or on an agreed to schedule
(R3.3) Within 30 days, provide details of changes made during misoperation investigation, commissioning, maintenance activities or emergency replacements due to failure of Protection System components
R4
(R4.2) Prior to implementing any planned change associated with R3.1, confirm that the owners of the Facility associated with the affected Interconnected Element accept any resulting PS changes
(R4.1) Within 90 days after receipt or according to an agreed upon schedule, review the PSS summary results and respond as to whether further action is required

Example Process

An example of the interaction between entities required to gather the information to perform an accurate study is ~~below~~provided below. This example is given as general guidance only and is not intended to represent all situations that may occur. More detailed examples are provided along with Figures 1-5 in the section that follows this example.

- The initiating entity (Entity A) will contact the interconnected entity (Entity B) and provide details of the proposed change(s) and may also request up-to-date Protection System information.
- Entities A and B will determine whether a new PSCS is required. In this example both agree that a new study is required. The study may be a joint study, individual studies, or a single study provided by Entity A and reviewed and approved by Entity B. In this example, the latter will occur.
- Upon receipt of the above request for information, Entity B will provide the information within 30 calendar days, or an agreed upon time frame.
- Entity A will perform a ~~Protection System Study~~PSCS using the information received.
- Entity A will provide a summary of the results of the study to Entity B within 90 calendar days of completing the ~~Protection System Study~~PSCS.
- Entity B will review the summary information and, within 90 calendar days of receiving the study results from Entity A, ~~confirm agreement that~~respond as to whether any coordination issues were identified, and if any further action is ~~achieved~~required.
  - In cases where the study reveals that changes to Protection Systems are needed, Entity B would propose to Entity A revisions that achieve acceptable results.
- ~~Documentation of the final agreement is required prior to implementation of planned changes.~~
  - Ultimately, both entities will collaborate in developing a mutually acceptable solution.

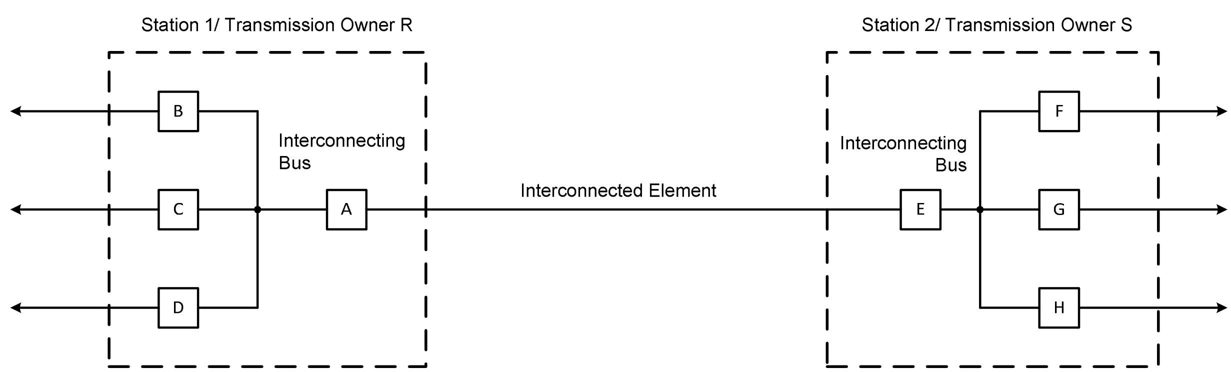
Diagrams

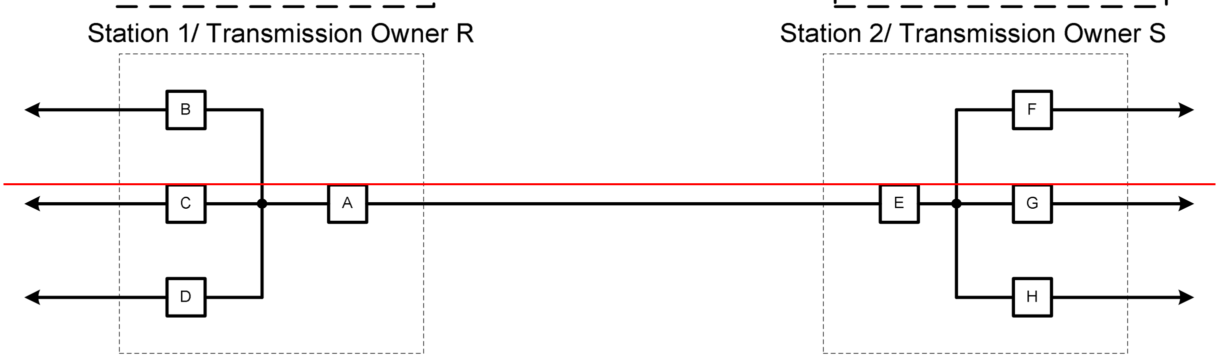
Introduction: The diagrams below are intended to provide guidance~~ related~~, to the ~~purpose of this standard between~~ owners of Facilities associated with the affected Interconnected Element~~.~~, for meeting the requirements of this standard. These examples are not intended to be inclusive of all situations and are based on the assumption that entities employ the appropriate engineering expertise and due diligence in developing settings for their Protection Systems. The examples given also assume a single owner as the initiator of a Protection System Coordination Study (PSCS) for the applicable Interconnected Element. In actuality, any owner or owners may initiate the process. After the reviews of the PSCS or a summary of results, and prior to implementation of ~~the~~ changes, the owners must ~~reach agreement on the final settings to achieve~~work together to resolve any coordination ~~of the Protection Systems.~~ issues identified during those reviews.

NOTES:

1. Protection System Coordination Studies are typically performed assuming maximum generation and all Facilities in service.
2. Protection Systems of the Transmission Owners, Generator Owners, and Distribution Providers described in the Figures and examples below do not include any systems or components enumerated in the 'Background Section' of this standard under "Other Aspects of Coordination of Protection Systems Addressed by Other Projects".

Figure 1

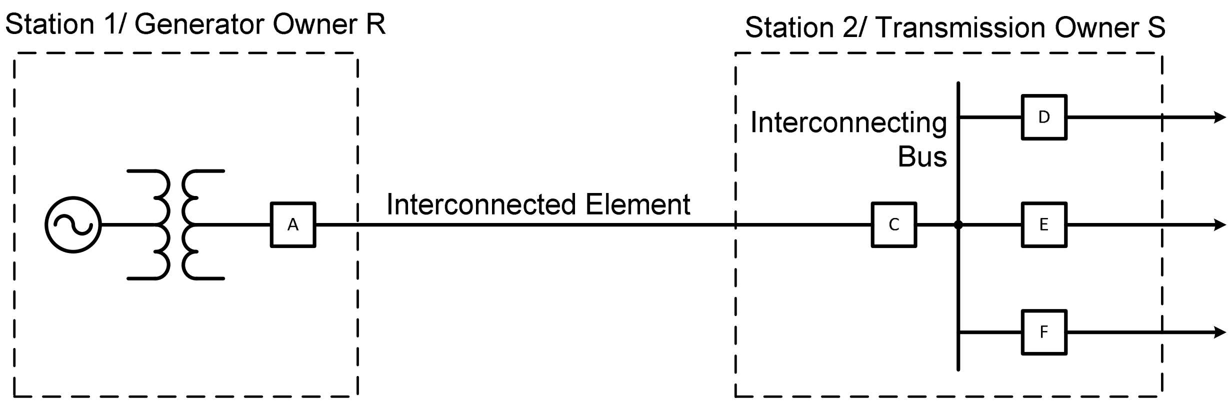


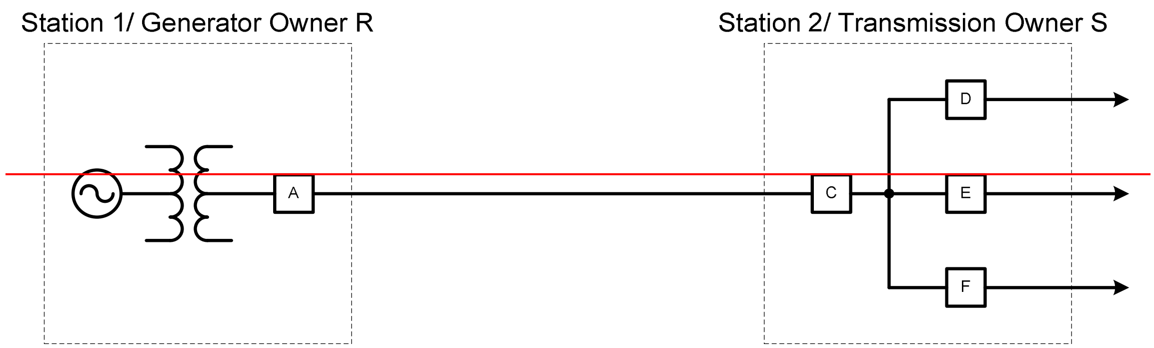


In Figure 1 above, the Interconnected Element between the Transmission Owners is the transmission line between Breakers A and E.

Example: For the purposes of conducting the ~~Protection System Study~~PSCS associated with the Facilities in Figure 1, Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers E, F, G, and H. ~~Likewise,~~ Likewise, Owner S is to develop proposed Protection System settings associated with Breaker E. Owner R is to review the Protection System settings associated with Breaker E (provided by Owner S) for coordination issues with the Protection System settings associated with Breakers A, B, C, and D.

Figure 2



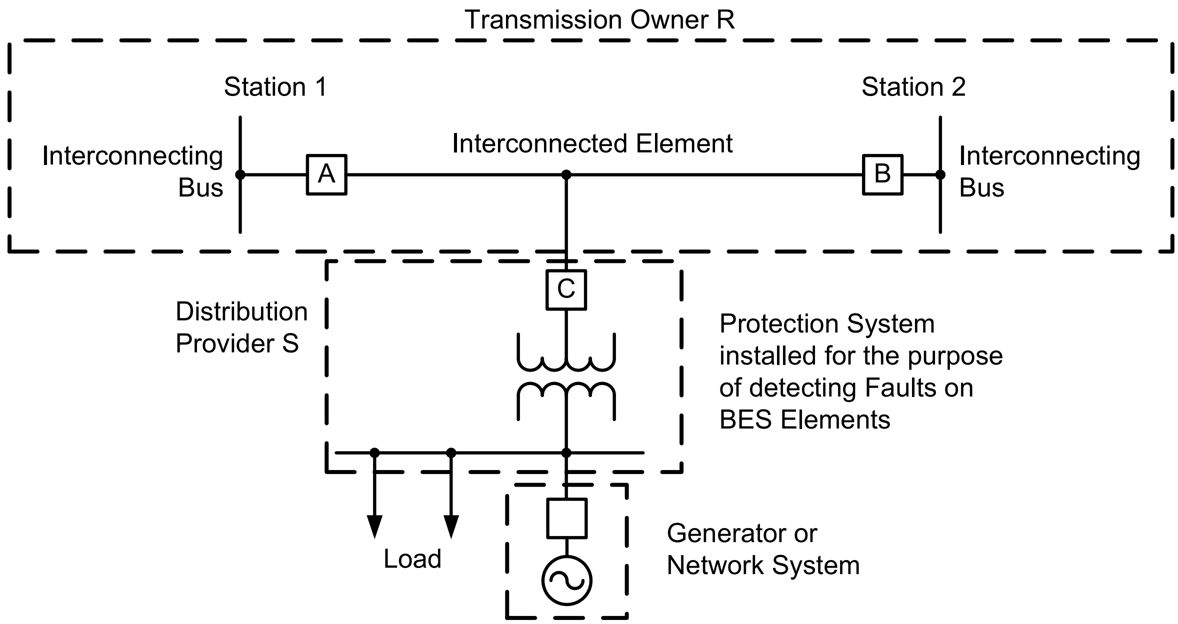


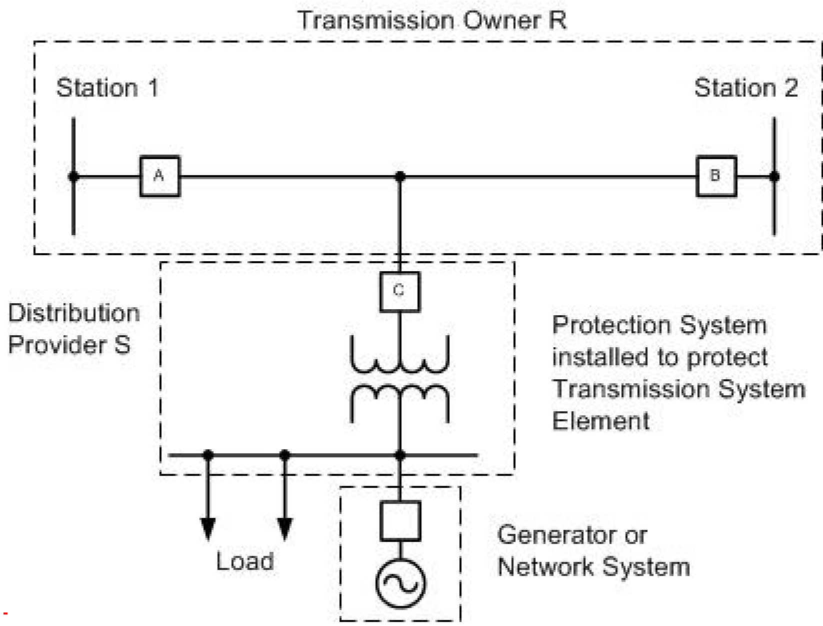
In Figure 2 above, the Interconnected Element between the Transmission Owner and the Generator Owner is the transmission line or bus between Breakers A and C.

Note: Depending on the actual configuration and/or ownership, ~~breaker~~Breaker A may, or may not, exist as a GSU unit high-side breaker or a line breaker.

Example: For the purposes of conducting the ~~Protection System Study~~PSCS associated with the Facilities in Figure 2, Owner R is to develop proposed Protection System settings associated with Breaker A. Transmission Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. ~~Likewise,~~Likewise, Owner S is to develop proposed Protection System settings associated with Breaker C. Generation Owner R is to review the Protection System settings associated with Breaker C (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

Figure 3





In Figure 3 above, the Interconnected Element between the Transmission Owner and the Distribution Provider is the transmission line (or tap) between Breaker C and the point of connection to the line between Breakers A and ~~Breaker C~~B.

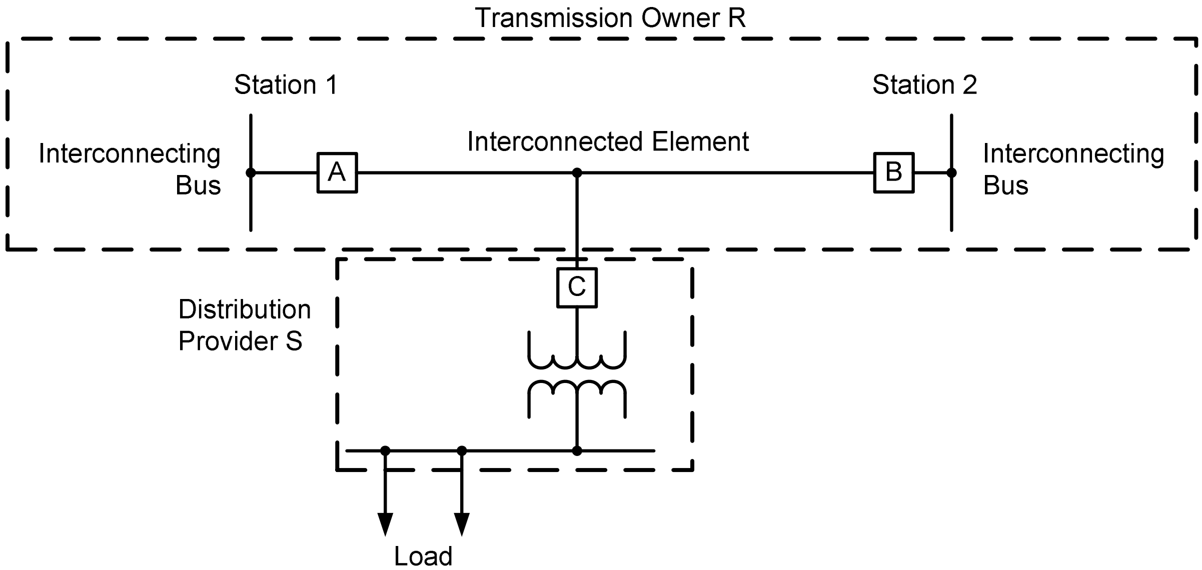
Example: For the purposes of conducting the ~~Protection System Study~~PSCS associated with the Facilities in Figure 3, Distribution Provider S is to develop proposed Protection System settings associated with Breaker C. Transmission Owner R is to review the Protection System settings associated with Line Breaker C (provided by Distribution Provider S) for coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2.

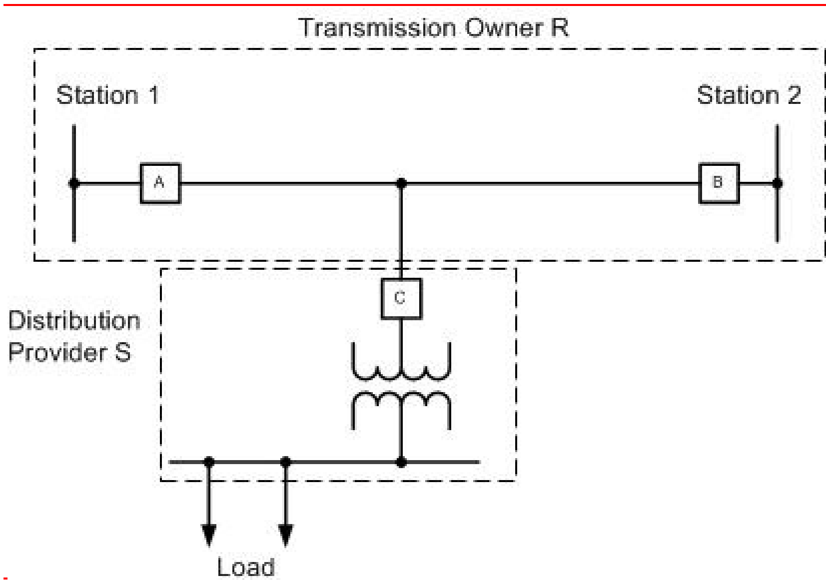
Notes:

~~A Protection System Study~~A PSCS is required per this standard for this example if a Protection System at the Distribution Provider's substation is ~~designed to detect~~installed for the purpose of detecting Faults on ~~the~~ BES ~~Transmission System~~Elements.

~~"~~Protection Systems installed ~~to detect faults on~~ for the purpose of detecting Faults on BES ~~Transmission System" are~~Elements do not ~~inclusive of those~~include relays that, though they may operate for such ~~faults, but~~Faults, are not installed specifically for that purpose ~~(i.e. transformer overcurrent, reverse power, etc.).~~. As an example, reverse power relays are often installed to detect situations where the transmission source for a power transformer becomes de-energized ~~and~~(for whatever reason) while the distribution bank remains energized from a source on the low-voltage side ~~of the transformer and~~. In this case, the settings ~~are~~of the reverse power relay are typically calculated based on the charging current of the transformer from the low-voltage side. Although ~~these~~ relays installed and set in this manner may operate as a result of a Fault on a BES Element, they are not ~~"~~specifically installed ~~to detect faults on~~for the ~~BES Transmission System."~~purpose of detecting that Fault.

Figure 4





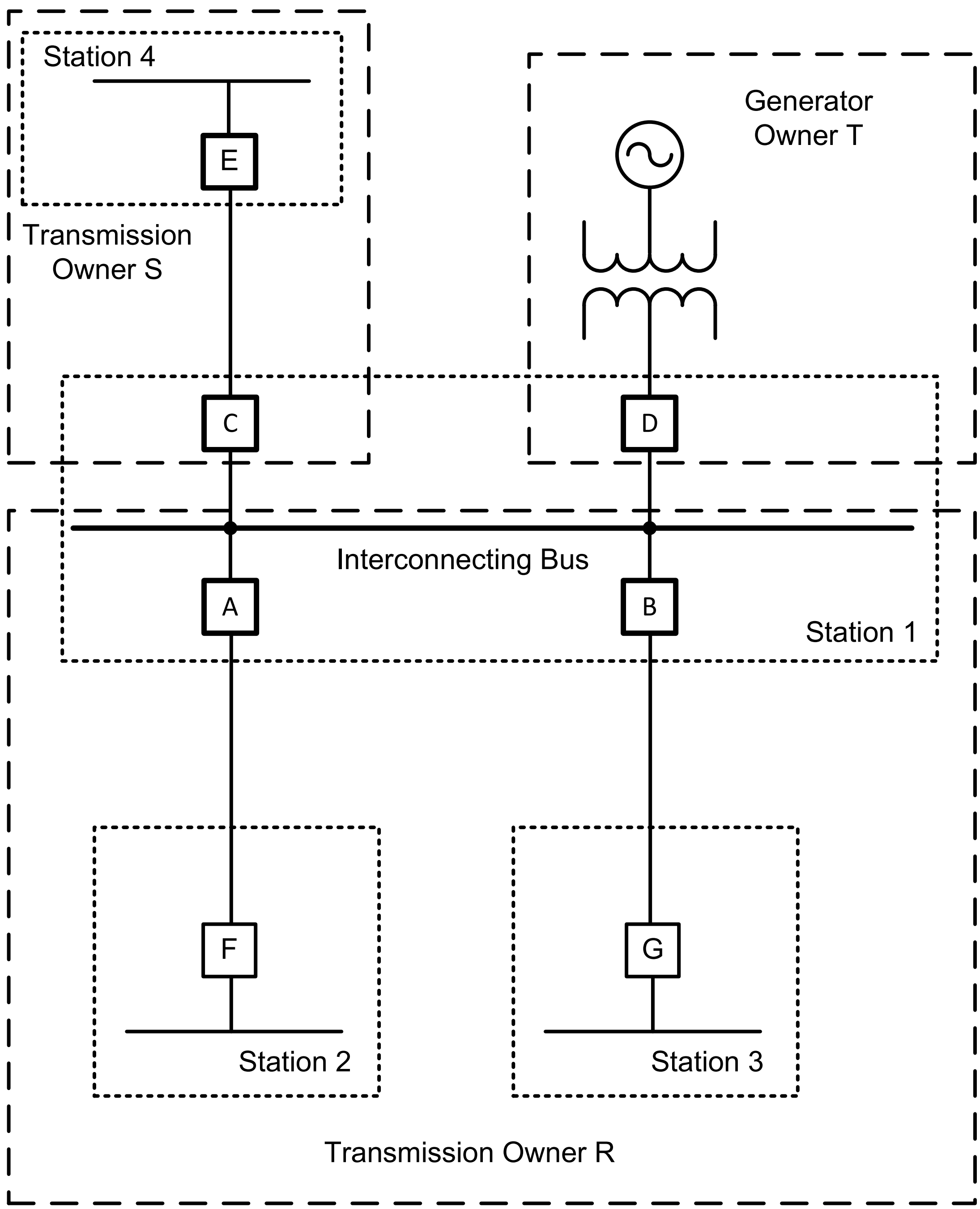
In Figure 4 above, the Interconnected Element between the Transmission Owner and the Distribution Provider is the transmission line or tap between the line and Breaker C.

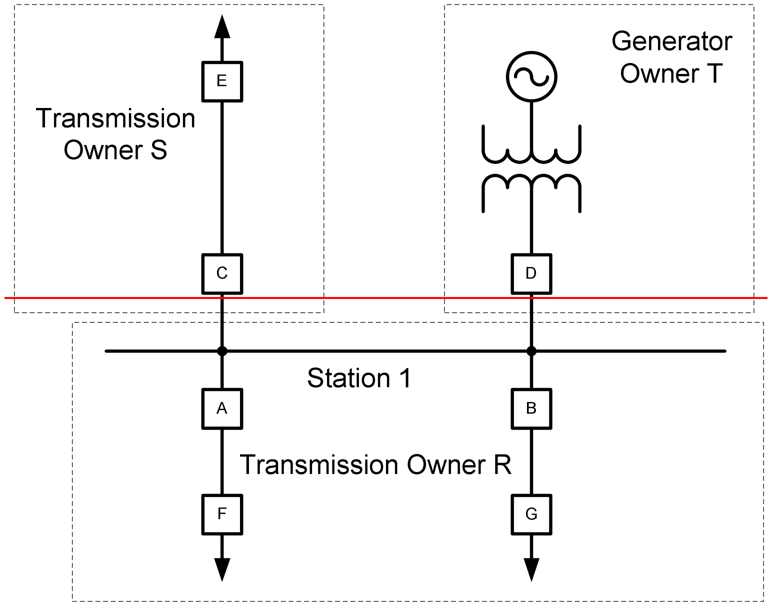
Note: No specific ~~Protection System Study~~PSCS is required per this standard for this example since the Protection System at the Distribution Provider's substation is not ~~designed to protect~~installed for the purpose of detecting Faults on BES ~~transmission system~~ Elements.

Figure 5

Transmission/Generation Facility with Multiple Owners

Note: In a large majority of cases, Figure 2 would be applicable for most generator interconnections. In Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T.


Station 4
E
Transmission
Owner S
Generator
Owner T
C
D
Interconnecting Bus
A
B
Station 1
F
G
Station 2
Station 3
Transmission Owner R



In Figure 5 above, the Interconnected Element between the Transmission Owners R and S and ~~the Generation~~Generator Owner T is the common Transmission bus. In this example, Transmission Owner S and Generator Owner T are not directly interconnected to each other at ~~Transmission~~ Station 1~~, and all~~. All direct interconnections are between Owner R and each of the other Owners connected to the common bus at Station 1.

Example: For the purposes of conducting the ~~Protection System Study~~PSCS associated with the Facilities in Figure 5:

Owner S is to develop proposed Protection System settings associated with Breakers C and E.

Owner T is to develop proposed Protection System settings associated with Breaker D, the generator, and its associated equipment.

Owner R is to develop proposed Protection System settings associated with Breakers A, B, F and G.

Owner R is to review the Protection System settings associated with Breaker C, E, D, and the generator Protection System (provided by Owners S and/or T) for coordination issues with the Protection System settings associated with Breakers A~~,~~ and B.

Owner S is to review the Protection System settings associated with Breakers A, F, B, G, D, and the generator Protection System (provided by Owners R and/or T) for coordination issues with the Protection System settings associated with Breaker C. To perform this review, it will be necessary that Transmission Owner R provide Owner S with its settings for Breakers A, F, B, and G, as well as the settings for Breaker D and generator Protection System settings provided to Owner R by Generator Owner T.

Owner T is to review the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R and/or S) for coordination issues with the Protection System settings associated with Breaker D or the ~~Protection Systems associated with~~ generator Protection System~~s~~. In order to perform this review, it will be necessary that Transmission Owner R provide Generator Owner T with its settings for Breakers A, F, G, and B, as well as the settings for Breaker C and E provided to Owner R by Transmission Owner S.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Draft 1 of SAR posted for comment June 11, 2007 – July 10, 2007.
2. SAR approved on August 13, 2007.
3. First posting of revised standard PRC-001-2 on September 11, 2009.
4. Transitioned from a revision of PRC-001-1 to development of PRC-027-1 based on industry comments, Quality Review feedback, and consideration of FERC directives relative to the existing requirements of PRC-001-1.
5. Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012.

~~5.~~6. Draft 2 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from November 16 – December 17, 2012.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPC SDT) created a new results-based standard, PRC-027-1, with the stated purpose 'to coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the ~~least number of power system Elements are isolated to clear~~desired sequence during Faults.'~~.~~ This standard incorporates and ~~enhances~~ clarifies the coordination aspects of Requirements ~~R3~~ R2 and ~~R4~~ R3 from PRC-001-~~1~~ 2 (~~now~~ formerly ~~R2~~ R3 and ~~R3~~ R4 of PRC-001-~~2~~1). The SPC SDT is requesting a posting for stakeholder comments ~~under~~ for a 30-day formal comment period with a parallel successive ballot.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period with Parallel Successive Ballot	~~November 2012~~June 2013
Conduct Recirculation Ballot	~~January~~August 2013
BOT Adoption	~~August~~November 2013

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is ~~six~~12 months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is ~~six~~12 months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. For Interconnected Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2007-06 – PRC-027-1	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here.

The following terms are defined for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

Interconnected Element: ~~An~~A BES Element that electrically joins facilities owned by:
a) separate ~~Functional~~Registered Entities, ~~including those Functional Entities that are a part of~~or
b) the same Registered Entity~~.~~ that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

Protection System Coordination Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Coordination for Performance During Faults**

2. **Number:** PRC-027-1

3. **Purpose:** To coordinate Protection Systems for Interconnected Elements, such that ~~the least number of power system Elements are isolated to clear~~Protection System components operate in the desired sequence during Faults.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   ~~**4.2 Facilities:**~~

   4.2 Facilities: For the purpose of the requirements contained herein, the following Protection Systems owned by each Functional Entity in 4.1 above are those to which these requirements are applicable.

   4.2.1 Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements

5. **Background:**

On December 7, 2006, the NERC Planning Committee approved the assessment of Reliability Standard PRC-001 – System Protection Coordination, prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF noted problems with the applicability to entities and vagueness of requirements in the existing PRC-001-1 reliability standard. The SPCTF concluded that the deficiencies of Reliability Standard PRC-001-1 were magnified by having requirements that addressed coordination of protection functions and capabilities in the operating and planning timeframes. Consequently, the SPCTF recommended that the requirements for the operating horizon and planning horizon be clearly delineated, and possibly divided into two standards.

The NERC Standards Committee approved a Standard Authorization Request that included the modifications noted by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC SDT) posted an initial draft of Reliability Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC SDT attempted to address all issues identified by the SPCTF assessment of PRC-001-1. The SPC SDT responded to the comments from the initial posting of PRC-001-2, and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC Quality Review (QR) in December 2010. Based on the results from the QR, and after informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to follow the SPCTF recommendation and focused their knowledge and expertise on developing a new results-based standard, concentrating on the reliability aspects (the coordination of new and existing protective systems in the planning horizon) associated with Requirements R3 and R4 of PRC-001-1. These aspects of coordination are incorporated and ~~enhanced~~ clarified in the proposed Reliability Standard PRC-027-1 – Protection System Coordination for Performance During Faults with the stated purpose:

> *"To coordinate Protection Systems for Interconnected Elements, such that ~~the least number of power system Elements are isolated to clear~~Protection System components operate in the desired sequence during Faults."*

Additionally, the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address "the appropriate use of time delays in relays," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination.

PRC-001-1 contained a non-specific training requirement (Requirement R1), three operating time frame requirements (Requirements R2, R5 and R6), and two planning requirements (Requirements R3 and R4). The SPC SDT transferred the responsibility of addressing the operating Requirements R2, R5, and R6 to the drafting team for Project 2007-03 Real-time Operations, charged with revising the TOP group of reliability standards. The Project 2007-03 drafting team retired Requirements R2, R5, and R6 of PRC-001-1 because they addressed data and data requirements that are now included in ~~the proposed~~ Reliability Standard TOP-003-2. The NERC Board of Trustees adopted Reliability Standards TOP-003-2 and PRC-001-2 on May 9, 2012.

The SPC SDT revised PRC-001-2. Revisions include the removal of Requirements R2 and R3 (formerly Requirements R3 and R4 of PRC-001-1). These two legacy requirements are being retired because the aspects of coordination they address are incorporated in the proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The SPCSDT believes the training aspects of Requirement R1 would be more appropriately addressed by the PER group of Reliability Standards. Consequently, the drafting team has recommended via the NERC Issues Database that the future drafting team charged with revising PER-005-1 incorporate the reliability objective of Requirement R1 into the revised standard. Until that occurs, Requirement R1 of PRC-001-2 must remain in the standard. In an effort to improve PRC-001-2 until it can be fully retired, the drafting team has provided a measure to accompany Requirement R1. The Applicability section was also updated to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)~~The SPC SDT is incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 in a new standard (as recommended by the SPCTF assessment), and focusing on the performance of Protection Systems during Faults. Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) will be retired upon appropriate regulatory approval of the proposed standards PRC-001-3 and PRC-027-1. The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard.~~

~~Additionally, the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address "the appropriate use of time delays in relays," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination.~~

Other Aspects of ~~c~~Coordination of Protection Systems ~~a~~Addressed by ~~o~~Other Projects:

Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects.

- Underfrequency Load shedding programs are addressed ~~by~~in PRC-006-1~~ (Project 2007-01 Underfrequency Load Shedding – pending FERC approval) and generator~~. Generator performance during frequency excursions is being addressed ~~by~~in PRC-024-1 ~~in~~by Project 2007-09 Generator Verification.
- Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed ~~by~~in PRC-024-1 ~~in~~by Project 2007-09, Generator Verification.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is being addressed ~~by~~in PRC-019-1 ~~in~~by Project 2007-09.
- Transmission relay loadability is addressed in PRC-023-~~1 and, pending FERC approval, PRC-023-~~2.
- Generator relay loadability will be addressed in PRC-025-1 by Phase 2 of Relay Loadability: Generation, in Project 2010-13.2.
- Protective relay response during power swings will be addressed ~~in~~by Phase 3 of Project 2010-13.3, Relay Loadability.
- Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and will be improved in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

The SPC SDT believes that including these other aspects of protection coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

B. Requirements and Measures

Rationale for R1:

Part 1.1 A Protection System Coordination Study (PSCS) is necessary to verify coordination of Protection Systems for existing and new Interconnected Elements. The drafting team defines the term "Interconnected Element" as "A BES Element that electrically joins facilities owned by: a) separate Registered Entities, or b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner)."

Part 1.1.1 The drafting team believes 60 calendar months is an appropriate period of time for entities to perform the PSCS required where no study exists. The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame.

Part 1.1.2 The drafting team believes that 12 calendar months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater Fault current change at an interconnecting bus, where such conditions may warrant a new PSCS, or to technically justify why no such study is required, e.g., when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current.

Part 1.1.3 The drafting team believes that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, or to technically justify why no such study is needed. The drafting team believes the timeframe associated with the requirement for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3, Part 3.1 is unnecessary because notification of such a change may occur weeks or years prior to the change. The initiating entity has the incentive to provide the identified information as soon as possible to ensure timely implementations. The drafting team believes that six months is an appropriate period of time for entities to perform the studies required or to technically justify why no such study is needed when details of changes are provided associated with Requirement R3 Part 3.3.

Part 1.2 The drafting team believes to properly ensure coordination of Protection Systems associated with Interconnected Element(s), all entities need to share the summary of results of a PSCS and assess the study results. The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS performed in accordance with Requirement R1, Part 1.1 to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s).

Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by both Registered Entities.

~~Rationale for R1:~~

~~Part 1.1 Protection System Studies are necessary to verify coordination of Protection Systems for existing and new Interconnected Element. The drafting team defines the term "Interconnected Element" as "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity."~~

~~Part 1.1.1 The drafting team believes 48 months is an appropriate period of time for entities to perform the Protection System Studies required where no study exists. The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame.~~

~~Part 1.1.2 The drafting team believes that 6 months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater Fault current deviation at an interconnecting bus, where such conditions may warrant a new Protection System Study, or to technically justify why no such study is required, i.e., when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current.~~

~~Part 1.1.3 The drafting team believes that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, or to technically justify why no such study is needed. The drafting team believes the timeframe associated with this requirement is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3 is unnecessary because notification of such a change may occur weeks or years prior to the change. The initiating entity has the incentive to provide the identified information as soon as possible to ensure timely implementations.~~

~~Part 1.2 The drafting team believes to properly ensure coordination of Protection Systems associated with Interconnected Element(s), all entities need to share the summary of results of a Protection System Study (PSS) and assess the study results. The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSS performed in accordance with Requirement R1 to the owner(s) of the Protection System(s) associated with the Interconnected Element(s).~~

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

1.1. Perform a Protection System Coordination Study (PSCS) for each of its Interconnected ~~Element on its System~~Elements as follows:

1.1.1 Within ~~48~~60 calendar months after the effective date of this standard, if no ~~Protection System Study~~PSCS for that Interconnected Element exists.

1.1.2 Within ~~six~~12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required.

1.1.3 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1~~ or Part 3.3.~~, or within six calendar months of being notified of a change as described in Requirement R3, Part 3.3; or technically justify why such a study is not required.

1.2. Within 90 calendar days after the completion of each ~~Protection System Study~~PSCS, provide to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s~~)~~), a summary of the results of each ~~Protection System Study~~PSCS performed pursuant to ~~this requirement~~Requirement R1, Part 1.1, (including, at a minimum, the ~~protective relay settings~~Protection Systems reviewed, ~~power system Elements to be isolated, contingencies evaluated,~~the associated Fault currents used, any issues identified, and any revisions or actions proposed).

M1. Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1. and 1.1.2, and 1.1.3 is a dated ~~Protection System Study~~PSCS, or the summary results of each ~~Protection System Study (either in~~ PSCS (hard copy or electronic file formats) demonstrating ~~that~~ the time frames specified or agreed to in Parts 1.1.1~~. and~~, 1.1.2~~.~~, and 1.1.3 were achieved. Acceptable evidence of a technical justification for not performing a ~~Protection System Study~~PSCS as specified in Parts 1.1.2 and 1.1.3 ~~could be~~may include, but is not limited to, documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any aspects of coordination.

M2. Acceptable evidence for Requirement R1, Part 1.2 is dated documentation demonstrating that the summary results of each ~~Protection System Study~~PSCS (hard copy or electronic file formats) ~~was~~were provided within the specified time frame to the owner(s) of the Protection System(s) associated with the Interconnected Element(s).

Rationale for R2: This requires a periodic review of Fault currents at the interconnecting bus and providing ~~to~~ the results to the applicable entities when ~~deviations~~changes occur that meet the criteria of Requirement R2 ~~criteria~~. It is important that interconnected Facility owners are kept aware of changes that could affect proper performance of their Protection Systems. The Transmission Owner is identified as the entity responsible for performing the short circuit studies because they maintain the data necessary to perform the studies. ~~The drafting team determined that 10% was an appropriate point to provide this information based on the fact that Protection Systems are typically set with margins above 10%.~~Note: short circuit studies are used to determine the Fault current values at the interconnecting bus where a PSCS exists. These studies are typically performed assuming maximum generation and all Facilities in service.

~~Part 2.1 Short circuit databases are customarily updated annually, so the~~The drafting team believes ~~24~~60 calendar months provides the entities flexibility to either technically justify why Fault current does not affect the Protection System coordination, or schedule and perform the ~~new~~ activities specified in Requirement R2, Parts 2.1 and 2.2.

The drafting team recognizes the coordination of some types of Protection Systems is unaffected by changes in Fault current and, where technically justified, can be exempted from the short circuit ~~studies and calculate the percent deviation.~~ review.

Part 2.1 The drafting team believes ~~studies associated with changes that would affect~~maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus are necessary quantities needed to review the coordination ~~in less time would be triggered by other requirements in this standard.~~.

Part 2.2 The drafting team is including this ~~formula~~equation to assure a consistent approach is used by each Transmission Owner when calculating the percent ~~deviation~~change in Fault current values.

R2. For each ~~Facility associated with an~~ Interconnected Element on its System, the Transmission Owner shall, once every 60 calendar months, technically justify why Fault current does not affect the Protection System coordination, or: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

~~2.1. At least once every 24 months:~~

~~2.2.~~2.1. Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Coordination Study (PSCS) is available per Requirement R1.

~~2.3.~~2.2. Calculate the percent ~~deviation~~change between the Fault current values (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent ~~Protection System Study~~PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.~~1~~.1, using the following equation:

$$\%\ \cancel{Deviation}Change = \cancel{\left|\frac{Iscs - Ipss}{Ipss}\right|}\left|\frac{Iscs - Ipscs}{Ipscs}\right| x\ 100$$

Where: I_{scs} = Fault current value from present short circuit study

And: I_{pscs} = Fault current value used in the most recent ~~Protection System Study~~PSCS

2.2.1 Within 30 calendar days after identification ~~where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates~~of a ~~deviation in Fault current~~change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (I_{scs}) to each owner of the Protection System associated with the Interconnected Element ~~the updated Fault current values (I_{scs}).~~.

M3. Acceptable evidence of technical justification for not performing a short circuit study as specified in Requirement R2, could be documented engineering analyses or assessments that demonstrate why Fault current does not impact any aspects of coordination.

~~M3.~~M4. Acceptable evidence for Requirement R2, ~~Part~~ Parts 2.1 and 2.2~~.1~~ is dated documentation (hard copy or electronic file formats) that contains the present Fault current values from the short circuit study for each interconnecting bus analyzed, and ~~that~~ identifies the percent ~~deviation~~change from the ~~most recent Protection System Study~~ Fault current values used in the most recent PSCS determined by the ~~formula~~equation.

~~M4.~~M5. Acceptable evidence ~~that the updated Fault current values (I_{scs}), along with~~for Requirement R2, Part 2.2.1 is dated documentation (hard copy or electronic file formats) ~~for Requirement R2, Part 2.2 was~~that the updated Fault current values (I_{scs}), were provided within the specified timeframe to each owner of the Protection System associated with the Interconnected Element.

Rationale for R3: This requires the transfer of appropriate information to the entities associated with each Interconnected Element due to circumstances identified in Parts 3.1, 3.2, and 3.3.

Part 3.1 The reliability objective of this requirement is to enable the process of conducting PSCSs by ensuring that the information is provided to the owner(s) of the Protection Systems associated with Interconnected Element(s). The drafting team believes that information about any proposed change or addition (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the Interconnected Element. The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list provided in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. Examples of changes to generator units that result in impedance changes could include replacements and re-ratings. This requirement also pertains to changes identified as a result of studies performed in Requirement 1, Part 1.1.

Part 3.2 The purpose of this requirement is to provide a means for an entity to receive the requested information in a timely manner in order to perform a PSCS, as required in Requirement 1, Parts 1.1.1, 1.1.2, and 1.1.3. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide this information. The requirement also provides some flexibility for the parties involved to determine an otherwise agreed-to schedule, if appropriate.

Part 3.3 The drafting team believes 30 calendar days is sufficient time to provide the information.

~~Rationale for R3: This requires the transfer of appropriate information to the entities associated with each Interconnected Element due to circumstances identified in Parts 3.1, 3.2, and 3.3.~~

~~Part 3.1 The reliability objective of this requirement is to enable the process of conducting Protection System Studies by ensuring that the information is provided to the owner(s) of the Protection Systems associated with Interconnected Element(s). The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. Examples of changes to generator units that result in impedance changes could include replacements and re-ratings. This requirement also pertains to changes identified as a result of studies performed in Part 1.1.~~

~~Part 3.2 The purpose of this requirement is to provide a means for an entity to receive the requested information in a timely manner in order to perform a Protection System Study, as required in Parts 1.1.1, 1.1.2, and 1.1.3. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide this information. The requirement also provides some flexibility for the parties involved to determine an otherwise agreed-to schedule, if appropriate.~~

~~Part 3.3 The drafting team believes 30 calendar days is sufficient time to provide the information.~~

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnected Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

3.1. Details for any proposed change or addition~~s~~ listed below; either at an existing or new Facility associated with the Interconnected Element; or at other ~~f~~Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).

- New installation, replacement with different types, or modification of ~~:~~ protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios
- Changes to a transmission system Element that ~~change~~alter any sequence or mutual coupling impedance
- Changes to generator unit(s) that result in a change in impedance
- Changes to the generator step-up transformer(s) that result in a change in impedance

3.2. Requested information related to the coordination of Protection Systems associated with an Interconnected Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule.

3.3. Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.

~~M5.~~M6. Acceptable evidence for Requirement R3, Part 3.1 may include, but is not limited~~,~~ to, documentation (hard copy or electronic file formats) demonstrating that a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) ~~in hard copy or electronic file formats~~ as identified in the bulleted list ~~for Requirement R3, Part 3.1~~, was provided to each responsible entity connected to the same Interconnected Element.

~~M6.~~M7. Acceptable evidence for Requirement R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was provided according to the agreed-upon schedule, or within 30 calendar days absent such an agreement.

~~M7.~~M8. Acceptable evidence for Requirement R3, Part 3.3 is dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the changes made was provided within 30 calendar days.

Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with Interconnected Elements affirm that the Protection System(s) applied are acceptable per the conditions identified in Parts 4.1 and 4.2.

Part 4.1 The drafting team believes 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with Interconnected Elements to review the summary results of a PSCS and respond. Note: Per Requirement R1, Part 1.2, at a minimum, the summary results of a PSCS must include the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. The response should indicate acceptance with the review results/conclusions; or rejection of or disagreement with the review results/conclusions and offer of suggestions/modifications to resolve any identified coordination issues. The drafting team recognizes there could be situations where one owner may not agree with the other owner's protection philosophy but they accept the proposed changes since no coordination issues were identified.

Part 4.2 The drafting team believes that proposed changes or modifications (including project schedules) to Facilities associated with the Interconnected Element, as described in Requirement R3, Part 3.1, or modifications suggested in Requirement R4, Part 4.1 must be communicated and accepted prior to the in-service date. Acceptance assures that the coordination of Protection Systems associated with the affected Interconnected Element is achieved.

~~Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with Interconnected Elements confirm that the Protection System(s) applied are acceptable per the conditions identified in Parts 4.1 and 4.2.~~

~~Part 4.1 The drafting team believes 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with Interconnected Elements to review the summary results of a Protection System Study. If any issues are identified that require changes then respond whether further action is required.~~

~~Part 4.2 The drafting team believes that proposed modifications (including project schedules) to Facility changes associated with the Interconnected Element, as described in Requirement R3, Part 3.1, must be communicated and accepted prior to the in-service date. Acceptance assures that the coordination of Protection Systems associated with the affected Interconnected Element is achieved.~~

R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a ~~Protection System Study, as described in~~PSCS (per Requirement R1, Part 1.2~~,~~) and respond ~~as~~ to ~~whether further action is required.~~ the other owner(s):

- Accepting the results, or
- Rejecting the results and suggesting modifications to resolve any identified coordination issues.

4.2. Prior to implementing any ~~planned~~proposed change(s) or modifications associated with Requirement R3, Part 3.1~~, confirm the~~ or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element ~~accept any resulting~~have accepted the Protection System(s) changes including the resolution of any identified coordination issues.

~~M8.~~M9. Acceptable evidence for Requirement R4, Part 4.1 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement.

~~M9.~~M10. Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that ~~confirmation of acceptance was achieved,~~ prior to implementation of any ~~planned~~proposed Protection System(s) changes or modifications, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System ~~at~~associated with an Interconnected ~~Facility~~Element shall each keep data or evidence to show compliance with Requirements R1, R2, R3, and R4, and Measures M1 through ~~M9~~M10, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner ~~and~~or Distribution Provider that owns a Protection System at a Facility associated with an Interconnected Element is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity performed a Protection System Coordination Study on an Interconnected Element ~~per~~as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus ~~per~~as required in Requirement R1, Part 1.1.2, or ~~documented~~technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided the Protection	The responsible entity performed a Protection System Coordination Study on an Interconnected Element ~~per~~as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days~~.~~ but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus ~~per~~as required in Requirement R1, Part 1.1.2, or ~~documented~~technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to ~~40~~45 calendar days. OR The responsible entity	The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus ~~per~~as required in Requirement R1, Part 1.1.2, or ~~documented~~technically justified why a study was not required, but was late by more than ~~40~~45 calendar days but less than or equal to ~~50~~60 calendar days. OR The responsible entity	The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus ~~per~~as required in Requirement R1, Part 1.1.2, or ~~documented~~technically justified why a study was not required but was late by more than ~~50~~60 calendar days. OR The responsible entity provided the Protection

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by less than or equal to 10 calendar days ~~or less~~.	provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar days. OR The responsible entity failed to perform a Protection System Coordination Study on an Interconnected Element ~~per~~in accordance with Requirement R1, Parts 1.1.1, 1.1.2, or 1.1.3~~, or document~~. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2 or 1.1.3. OR The responsible entity failed to provide Protection System Coordination Study results in accordance with Requirement R1,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Part 1.2.
R2	Long-term Planning	Medium	For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by less than or equal to 30 calendar days. OR The Transmission Owner performed a short circuit study, as ~~described~~required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days.	For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The Transmission Owner performed a short circuit study as ~~described~~required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to ~~40~~60 calendar days.	For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The Transmission Owner performed a short circuit study as ~~described~~required in Requirement R2, Part 2.1, but was late by more than ~~40~~60 calendar days but less than or equal to ~~50~~90 calendar days.	~~The~~ For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 90 calendar days. OR The Transmission Owner performed a short circuit study as ~~described~~required in Requirement R2, Part 2.1, but was late by more than ~~50~~90 calendar days. OR The Transmission Owner failed to perform a short circuit study, as ~~described~~required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as ~~described~~required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as ~~described~~required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as ~~described~~required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	percent ~~deviation~~change between the Fault currents, according to the ~~formula~~equation designated in Requirement R2, Part 2.~~1~~2. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as ~~described~~required in Requirement R2, Part 2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnected Element, the ~~changes in~~updated Fault ~~currents~~current values, as required in Requirement R2, Part 2.2.1.
R3	Operations Planning	Medium				The responsible entity failed to provide ~~information to~~ the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			The responsible entity provided the requested information ~~per~~required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days~~ or less~~. OR The responsible entity provided the ~~required~~ information ~~identified~~required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days~~ or less~~.	The responsible entity provided the requested information ~~per~~required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the ~~required~~ information ~~identified~~required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information ~~per~~required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the ~~required~~ information ~~identified~~required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	owner(s) of the Facility associated with the Interconnected Element, details for any proposed change or addition identified in Requirement R3, Part 3.1. OR The responsible entity provided the requested information ~~per~~required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the ~~required~~ information ~~identified~~required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the ~~requested~~ information required in Requirement R3, Part 3.3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The responsible entity ~~confirmed acceptance~~responded in more than 90 calendar days but less than or equal to 100 calendar days following the receipt of the summary results of the Protection System Coordination Study~~ per~~, as required in Requirement R4, Part 4.1~~, but was late by 10 calendar days or less~~.	The responsible entity ~~confirmed acceptance~~responded in more than 100 calendar days but less than or equal to 110 calendar days following the receipt of the summary results of the Protection System Coordination Study~~ per~~, as required in Requirement R4, Part 4.1~~, but was late by more than 10 calendar days but less than or equal to 20 calendar days~~.	The responsible entity ~~confirmed acceptance~~responded in more than 110 calendar days but less than or equal to 120 calendar days following the receipt of the summary results of the Protection System Coordination Study~~ per~~, as required in Requirement R4, Part 4.1~~, but was late by more than 20 calendar days but less than or equal to 30 calendar days~~.	The responsible entity ~~confirmed acceptance~~responded in more than 120 calendar days following the receipt of the summary results of the Protection System Coordination Study~~ per~~, as required in Requirement R4, Part 4.1~~, but was late by more than 30 calendar days.~~. OR The responsible entity failed to ~~confirm acceptance of~~review the summary results of the Protection System Coordination Study ~~per~~provided to them in accordance with Requirement R4, Part 4.1. OR The responsible entity failed to ~~confirm acceptance of the planned~~respond to the other owners in accordance with Requirement R4, Part

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						4.1. OR The responsible entity failed to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element accepted the Protection System(s) changes ~~pursuant to R4, Part 4.2~~including the resolution of any identified coordination issues, prior to implementation of those changes, as required in Requirement R4, Part 4.2.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Purpose:

To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.

This standard requires that separate Registered Entities communicate with each other to coordinate Protection System components on existing Interconnected Elements; and communicate with each other prior to the energization of new or modified Protection Systems associated with Interconnected Elements. The goal of the coordination is to verify that the Protection Systems intended for sensing Faults will operate in the desired sequence for internal and external Faults on the Interconnected Element.

Requirement R1:

This requirement directs the ~~performance of~~applicable entities to perform a Protection System ~~Studies~~Coordination Study (PSCS) for every Interconnected Element to verify coordination of existing Protection Systems where no recent study exists; or when Facility configuration changes are made, or where Fault current ~~deviations~~changes of 10% or more have occurred. In developing the language to define ~~Protection System Study~~a PSCS, the System Protection Coordination Standard Drafting Team (~~SPC SDT~~SPC SDT) considered various reference books discussing protective relaying theory and application, along with the following description of "coordination of protection" from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Using the reference material cited above as guidance, the drafting team defined the term Protection System Coordination Study (PSCS) for use within the PRC-027-1 Reliability Standard as:

> "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults."

~~Protection System Studies~~PSCSs comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in ~~Protection System Studies~~PSCSs include maximum generation with the transmission system under normal operating conditions and under single contingency conditions. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), and adequate directional polarizing quantities.

The drafting team believes applicable entities should have a documented ~~Protection System Study~~PSCS for each Interconnected Element to validate the Protection Systems associated with those Interconnected Elements perform in a manner consistent with the purpose of this Standard. Additionally, the drafting team believes that ~~48~~60 calendar months is an appropriate amount of time for entities to perform the initial studies expected under this requirement. This period considers the time some entities may require to create project scopes, acquire proposals, and secure contracts to hire external resources that may be needed to perform the studies. The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with Interconnected Elements that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.

Parts 1.1.2 and 1.1.3 further direct that ~~Protection System Studies~~PSCSs must be completed under the following two circumstances:

1. After notification of an identified 10% or greater ~~deviation~~change in Fault current~~,~~ (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1), the notified entities must perform a new ~~Protection System Study~~PSCS of the Interconnected Element or document why a study is not required. The drafting team recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater ~~deviation~~change in Fault current may not necessitate a new ~~Protection System Study~~PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the ~~six~~ 12-calendar month time frame associated with this requirement represents a reasonable period to perform the studies that are required after identification by the ~~24~~ 60-calendar month Fault current review.

2. After proposing or being notified of a change at a Facility associated with the Interconnected Element, entities must perform a new ~~Protection System Study~~PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the proposed or notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new ~~Protection System Study~~PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the timeframe associated with ~~this requirement~~performing a PSCS for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3, Part 3.1 is unnecessary because notification of such a change may occur weeks or years prior to the change due to the wide variety of

conditions that may be associated with a particular change. The drafting team sees the entity initiating any change as having the incentive to move this along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2. The drafting team believes that six calendar months is an appropriate period of time for entities to perform the studies required, or to technically justify why no such study is needed, when details of changes are provided associated with Requirement R3 Part 3.3.

Requirement R1, Part 1.2 directs the entity performing the ~~Protection System Study~~PSCS to provide a summary of the study results to the affected Interconnected Element owner(s). The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS it performed to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s). (Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that meets the requirements for a summary of the results of the PSCS would be sufficient for use by both Registered Entities.) As guidance, the drafting team lists the following inputs and results of a ~~Protection System Study~~PSCS that may be included in the summary provided pursuant to this requirement:

1. A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Facility, and which were reviewed for coordination of protective relays as part of the study, including the contingencies used in the evaluation.
2. ~~Data used to determine Fault currents in performing the study, along with a~~A listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Facility under study.
3. A listing of any issues associated with the relay settings of the other owner(s) at the Facility that were identified by the study.
4. Any proposed revisions to a Protection System or its protective relay settings that were identified by the study.

Requirement R2:

The drafting team investigated various inputs that would trigger a review of the existing ~~Protection System Studies~~PSCSs and determined, through the experience of the drafting team members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated ~~Protection System Study~~PSCS may be necessary. These variations could result from the accumulation of incremental changes over time. This requirement mandates the Transmission Owner either provide a technical justification stating why Fault current does not affect the Protection System coordination of a specific Interconnected Element or perform a periodic review of Fault currents.

Examples of Protection Systems where technical justifications may be used include:

1. Differential elements
2. Distance elements where infeed is not used in determining reach for the protection scheme.
3. Supervised overcurrent elements enabled by:
   - Loss of potential condition
   - Some communication assisted tripping
   - Switch-Onto-Fault (SOTF)
4. Reverse power, definite time &/or time overcurrent elements:
   - Designed to coordinate during maximum generation with the transmission system under normal operating conditions and ~~includes the calculation of the percent deviation between the~~ under single contingency conditions regardless of Fault current.
   - Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.).

The short circuit study provides the Fault current values used ~~in the~~ to calculate the percent change between the most recent ~~Protection System Study~~PSCS and the present Fault current values indicated by the short circuit study performed pursuant to ~~this requirement~~Requirement R2, Part 2.1. This calculation is necessary to identify Fault current changes that must be communicated in accordance with Requirement R2, Part 2.2. Short circuit studies are typically performed assuming maximum generation and all Facilities in service.

~~Polling of~~The drafting team ~~membership and various protection engineering committees indicates~~believes that ~~short circuit databases are customarily updated annually. Based on this information, the drafting team believes that requiring a 24-month periodic review of~~60 calendar months is an appropriate interval for technically justifying why Fault currents ~~provides entities additional flexibility to schedule and perform these studies and calculate the percent deviation, as described in Requirement R2, Part 2.1.~~ do not affect the Protection System coordination of a specific Interconnected Element, or for reviewing Fault currents. The drafting team believes studies associated with changes that would affect the coordination in less than ~~24~~60 calendar months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.2.1 further directs the Transmission Owner to, within 30 calendar days, inform each owner of the Facility associated with the Interconnected Element when short circuit studies indicate that 10% ~~deviations~~changes in Fault current have occurred at the interconnecting bus(s). The drafting team believes the 30-calendar day time frame associated with this requirement is reasonable for providing the Fault current information to the interconnected entity(s) and is consistent with other NERC reliability standards.

In Requirement R2, the Transmission Owner is identified as the ~~Functional Entity~~functional entity responsible for performing the ~~Fault current~~short circuit studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.

Requirement R3:

This directs the registered functional entity initiating any proposed change or addition to provide the details to the other affected entities of the Interconnected Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes. Documentation provided to these other owners may include, but is not limited to, power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings. The recipient will incorporate the applicable information into its ~~Protection System Studies~~PSCSs to evaluate whether changes are required.

The list of applicable changes provided in Requirement R3, Part 3.1 is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. The drafting team recognizes that Facility changes at other locations can impact the ~~Protection System Study~~PSCS of the Facility associated with the Interconnected Element; e.g., the addition of a large autotransformer bank or generator not directly ~~associated with~~connected to the Interconnected Element. The drafting team believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the drafting team sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2.

Requirement R3, Part 3.2 allows for entities to agree upon a schedule, appropriate to the circumstances, for providing the details needed to conduct a ~~Protection System Study~~PSCS or, absent such agreement, within 30 calendar days of a request for this information. This requirement provides a means for entities to receive requested information in a timely manner. In consideration of circumstances where the information may not be readily available or may be incomplete due the retirement of personnel, the purging of records, change of ownership, etc., it also provides the flexibility of mutually agreeing to a schedule for exchanging information. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide the requested information where no other agreement exists.

Additionally, this requirement includes a provision for providing details associated with changes to the previously agreed-upon coordination when changes are made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components Based upon the limited number of instances that would occur under such circumstances, the drafting team believes 30 calendar days after determining that changes are required is an appropriate time frame for providing the associated details to affected entities.

Requirement R4:

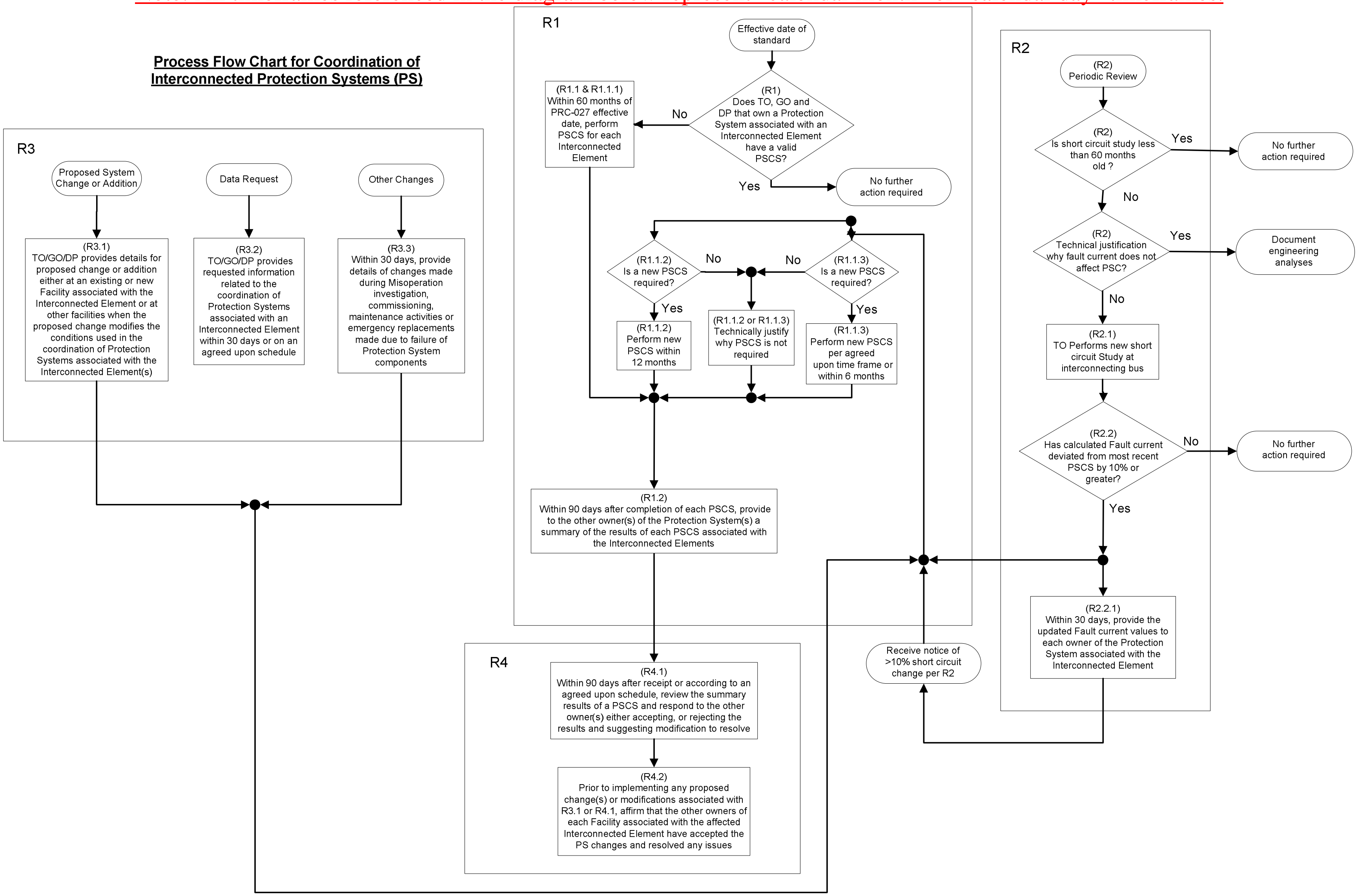
The reliability objective of this requirement is to bring the process of Protection System coordination full circle by gaining the confirmation of interconnected entities that their Protection Systems are coordinated consistent with the purpose of this standard. Cooperative participation of Facility owners in communicating Protection System(s) design, and study results will achieve coordination of Protection Systems for reliable operation of the BES during Faults.

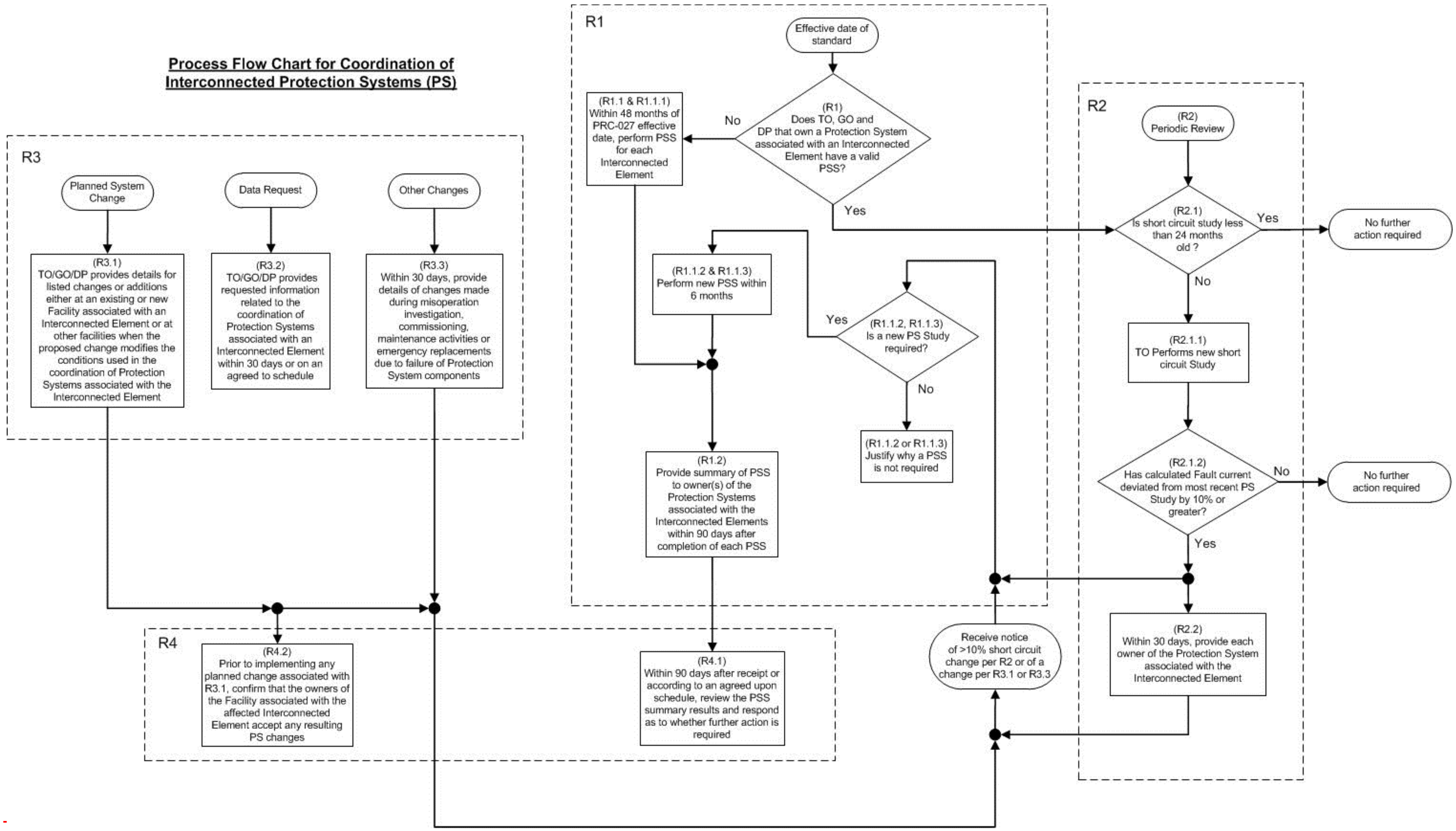
Requirement R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to review the summary results of a ~~Protection System Study~~PSCS, as described in Requirement R1, Part 1.2; ~~or absent acceptance propose revisions~~and respond as to ~~achieve acceptable results.~~whether they accepting or rejecting the results, and if rejecting, suggesting modifications to resolve any identified coordination issues. The drafting team believes 90 calendar days after receipt of the results of a ~~Protection System Study~~PSCS provides a reasonable time for the owners of Facilities to ~~resolve differences and confirm acceptance that their Protection Systems are coordinated~~review the summary results of a PSCS.

Requirement R4, Part 4.2 directs entities to ~~con~~affirm that ~~planned~~the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes as described in Requirement 3, Part 3.1 ~~are acceptable~~and Requirement 4, Part 4.1 prior to the in-service date of those changes. Any coordination issues identified during the review must be resolved prior to implementing the proposed changes. The purpose of ~~this requirement~~Requirement 4, Part 4.2 is to assure the effects ~~that planned~~the proposed changes have on Protection Systems at a Facility associated with the ~~affected~~ Interconnected Element have been considered by all affected entities.

Process Flow Chart: Below is a complete representation of the process, including the relationships between requirements:

Note: All timeframes referenced in the diagram below represent "calendar month" or "calendar day" timeframes.




Process Flow Chart for Coordination of Interconnected Protection Systems (PS)
R1
Effective date of standard
(R1) Does TO, GO and DP that own a Protection System associated with an Interconnected Element have a valid PSS?
No
(R1.1 & R1.1.1) Within 48 months of PRC-027 effective date, perform PSS for each Interconnected Element
Yes
(R1.1.2 & R1.1.3) Perform new PSS within 6 months
Yes
(R1.1.2, R1.1.3) Is a new PS Study required?
No
(R1.1.2 or R1.1.3) Justify why a PSS is not required
(R1.2) Provide summary of PSS to owner(s) of the Protection Systems associated with the Interconnected Elements within 90 days after completion of each PSS
R2
(R2) Periodic Review
(R2.1) Is short circuit study less than 24 months old ?
Yes
No further action required
No
(R2.1.1) TO Performs new short circuit Study
(R2.1.2) Has calculated Fault current deviated from most recent PS Study by 10% or greater?
No
No further action required
Yes
(R2.2) Within 30 days, provide each owner of the Protection System associated with the Interconnected Element
Receive notice of >10% short circuit change per R2 or of a change per R3.1 or R3.3
R3
Planned System Change
Data Request
Other Changes
(R3.1) TO/GO/DP provides details for listed changes or additions either at an existing or new Facility associated with an Interconnected Element or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element
(R3.2) TO/GO/DP provides requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 days or on an agreed to schedule
(R3.3) Within 30 days, provide details of changes made during misoperation investigation, commissioning, maintenance activities or emergency replacements due to failure of Protection System components
R4
(R4.2) Prior to implementing any planned change associated with R3.1, confirm that the owners of the Facility associated with the affected Interconnected Element accept any resulting PS changes
(R4.1) Within 90 days after receipt or according to an agreed upon schedule, review the PSS summary results and respond as to whether further action is required

-

Example Process

An example of the interaction between entities required to gather the information to perform an accurate study is ~~below~~provided below. This example is given as general guidance only and is not intended to represent all situations that may occur. More detailed examples are provided along with Figures 1-5 in the section that follows this example.

- The initiating entity (Entity A) will contact the interconnected entity (Entity B) and provide details of the proposed change(s) and may also request up-to-date Protection System information.
- Entities A and B will determine whether a new PSCS is required. In this example both agree that a new study is required. The study may be a joint study, individual studies, or a single study provided by Entity A and reviewed and approved by Entity B. In this example, the latter will occur.
- Upon receipt of the above request for information, Entity B will provide the information within 30 calendar days, or an agreed upon time frame.
- Entity A will perform a ~~Protection System Study~~PSCS using the information received.
- Entity A will provide a summary of the results of the study to Entity B within 90 calendar days of completing the ~~Protection System Study~~PSCS.
- Entity B will review the summary information and, within 90 calendar days of receiving the study results from Entity A, ~~confirm agreement that~~respond as to whether any coordination issues were identified, and if any further action is ~~achieved~~required.
    - In cases where the study reveals that changes to Protection Systems are needed, Entity B would propose to Entity A revisions that achieve acceptable results.
- ~~Documentation of the final agreement is required prior to implementation of planned changes.~~
    - Ultimately, both entities will collaborate in developing a mutually acceptable solution.

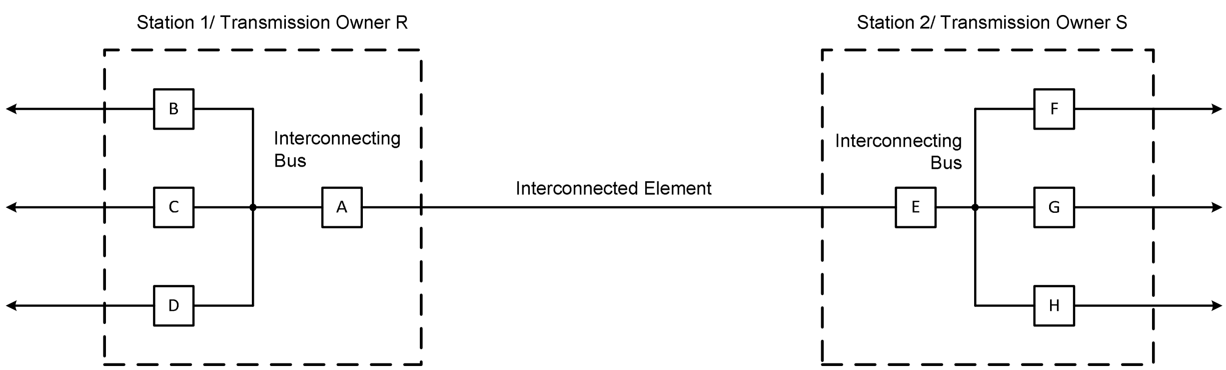
Diagrams

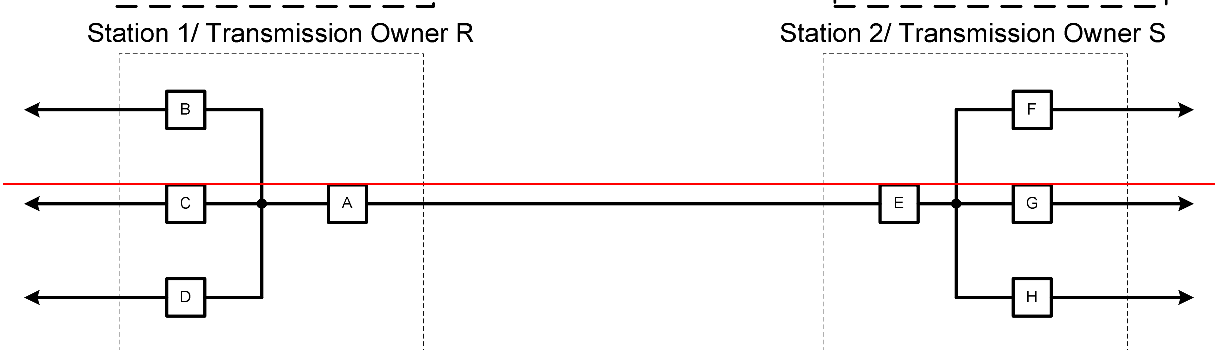
Introduction: The diagrams below are intended to provide guidance ~~related~~, to the ~~purpose of this standard between~~ owners of Facilities associated with the affected Interconnected Element~~.~~, for meeting the requirements of this standard. These examples are not intended to be inclusive of all situations and are based on the assumption that entities employ the appropriate engineering expertise and due diligence in developing settings for their Protection Systems. The examples given also assume a single owner as the initiator of a Protection System Coordination Study (PSCS) for the applicable Interconnected Element. In actuality, any owner or owners may initiate the process. After the reviews of the PSCS or a summary of results, and prior to implementation of ~~the~~ changes, the owners must ~~reach agreement on the final settings to achieve~~work together to resolve any coordination ~~of the Protection Systems.~~ issues identified during those reviews.

NOTES:

1. Protection System Coordination Studies are typically performed assuming maximum generation and all Facilities in service.
2. Protection Systems of the Transmission Owners, Generator Owners, and Distribution Providers described in the Figures and examples below do not include any systems or components enumerated in the 'Background Section' of this standard under "Other Aspects of Coordination of Protection Systems Addressed by Other Projects".

Figure 1

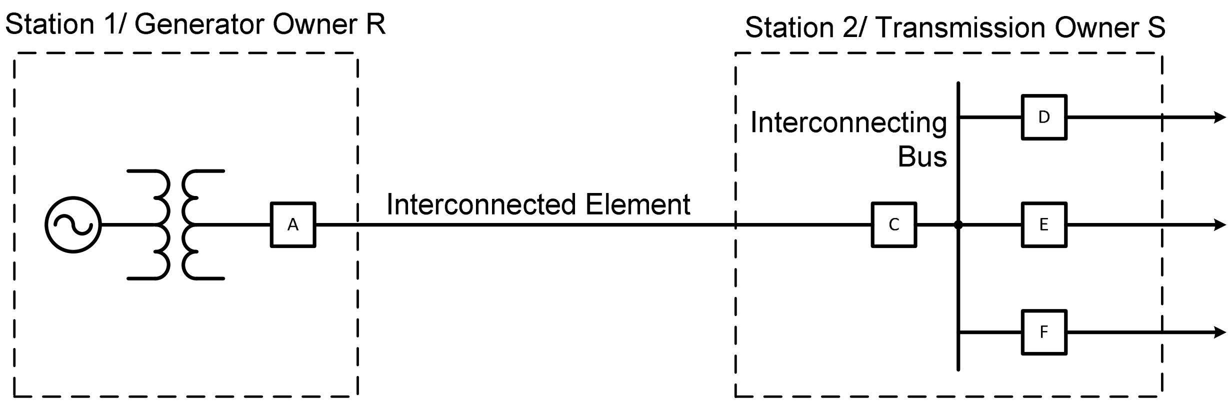


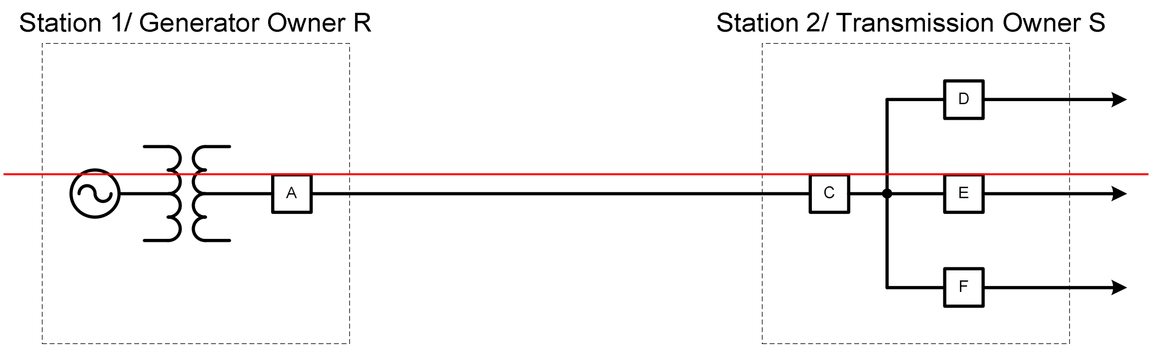


In Figure 1 above, the Interconnected Element between the Transmission Owners is the transmission line between Breakers A and E.

Example: For the purposes of conducting the ~~Protection System Study~~PSCS associated with the Facilities in Figure 1, Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers E, F, G, and H. ~~Likewise,~~ Likewise, Owner S is to develop proposed Protection System settings associated with Breaker E. Owner R is to review the Protection System settings associated with Breaker E (provided by Owner S) for coordination issues with the Protection System settings associated with Breakers A, B, C, and D.

Figure 2



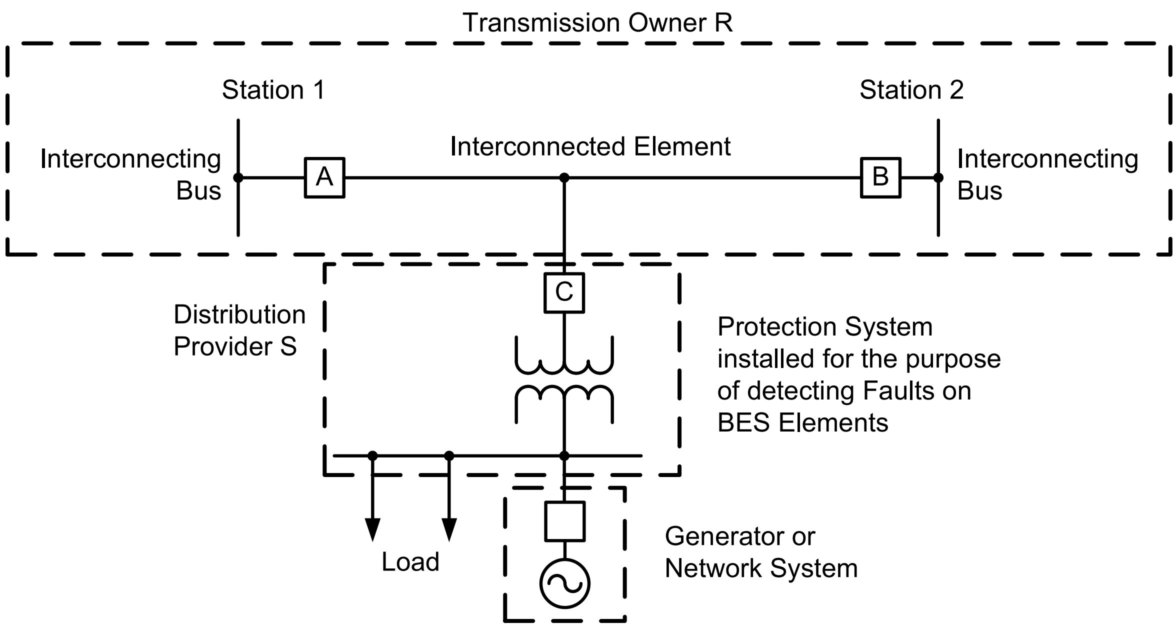


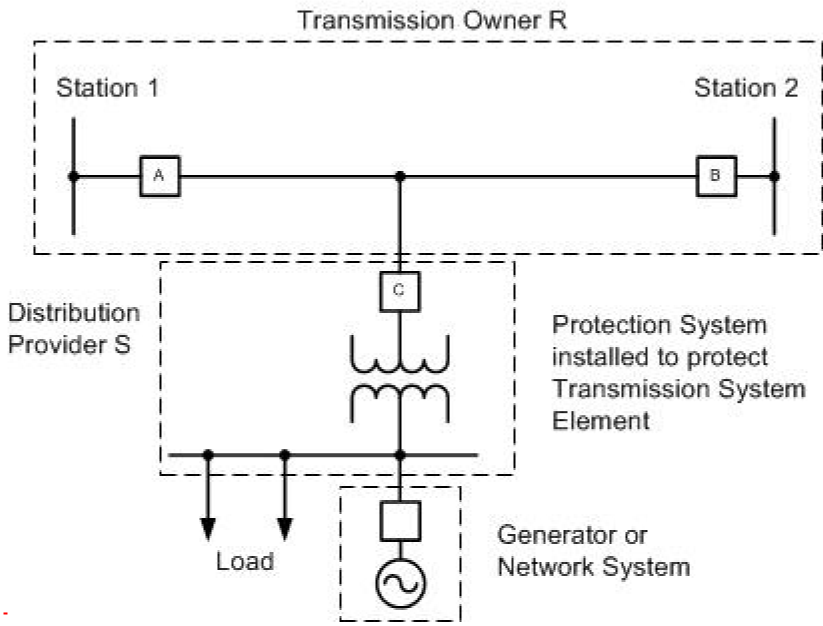
In Figure 2 above, the Interconnected Element between the Transmission Owner and the Generator Owner is the transmission line or bus between Breakers A and C.

Note: Depending on the actual configuration and/or ownership, ~~breaker~~Breaker A may, or may not, exist as a GSU unit high-side breaker or a line breaker.

Example: For the purposes of conducting the ~~Protection System Study~~PSCS associated with the Facilities in Figure 2, Owner R is to develop proposed Protection System settings associated with Breaker A. Transmission Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. ~~Likewise,~~Likewise, Owner S is to develop proposed Protection System settings associated with Breaker C. Generation Owner R is to review the Protection System settings associated with Breaker C (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

Figure 3





In Figure 3 above, the Interconnected Element between the Transmission Owner and the Distribution Provider is the transmission line (or tap) between Breaker C and the point of connection to the line between Breakers A and ~~Breaker C~~B.

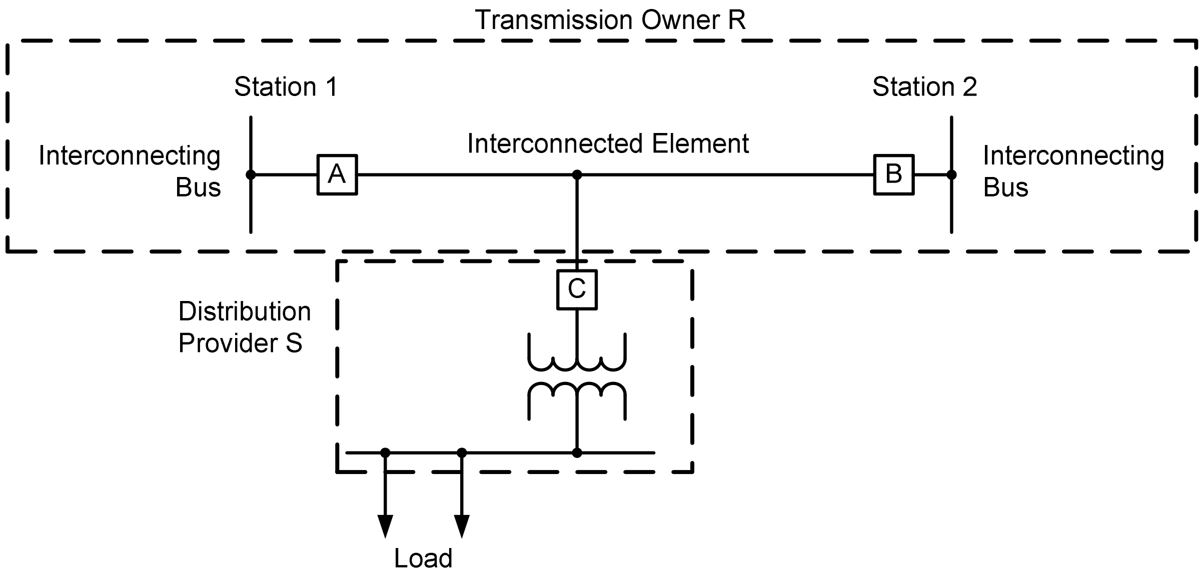
Example: For the purposes of conducting the ~~Protection System Study~~PSCS associated with the Facilities in Figure 3, Distribution Provider S is to develop proposed Protection System settings associated with Breaker C. Transmission Owner R is to review the Protection System settings associated with Line Breaker C (provided by Distribution Provider S) for coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2.

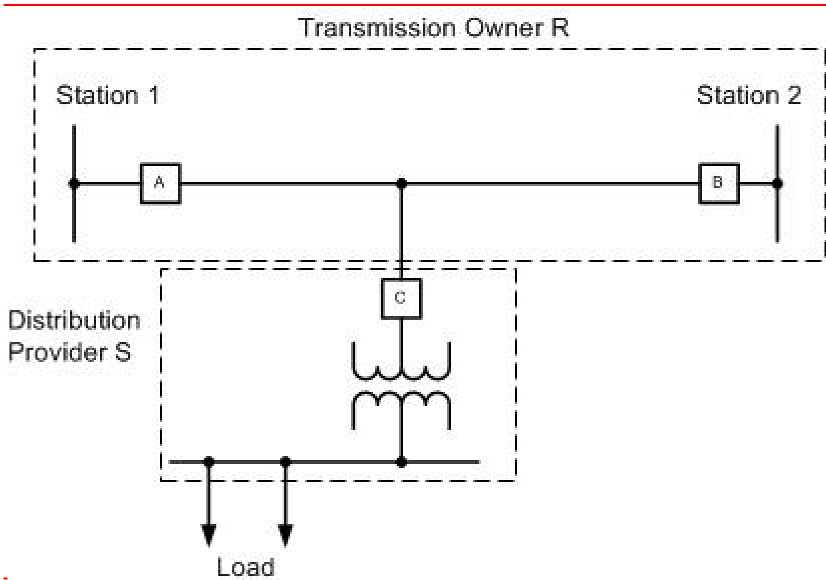
Notes:

~~A Protection System Study~~A PSCS is required per this standard for this example if a Protection System at the Distribution Provider's substation is ~~designed to detect~~installed for the purpose of detecting Faults on ~~the~~ BES ~~Transmission System~~Elements.

~~"~~Protection Systems installed ~~to detect faults on~~ for the purpose of detecting Faults on BES ~~Transmission System" are~~Elements do not ~~inclusive of those~~include relays that, though they may operate for such ~~faults, but~~Faults, are not installed specifically for that purpose ~~(i.e. transformer overcurrent, reverse power, etc.).~~ . As an example, reverse power relays are often installed to detect situations where the transmission source for a power transformer becomes de-energized ~~and~~(for whatever reason) while the distribution bank remains energized from a source on the low-voltage side ~~of the transformer and~~. In this case, the settings ~~are~~of the reverse power relay are typically calculated based on the charging current of the transformer from the low-voltage side. Although ~~these~~ relays installed and set in this manner may operate as a result of a Fault on a BES Element, they are not ~~"~~specifically installed ~~to detect faults on~~for the ~~BES Transmission System."~~purpose of detecting that Fault.

Figure 4





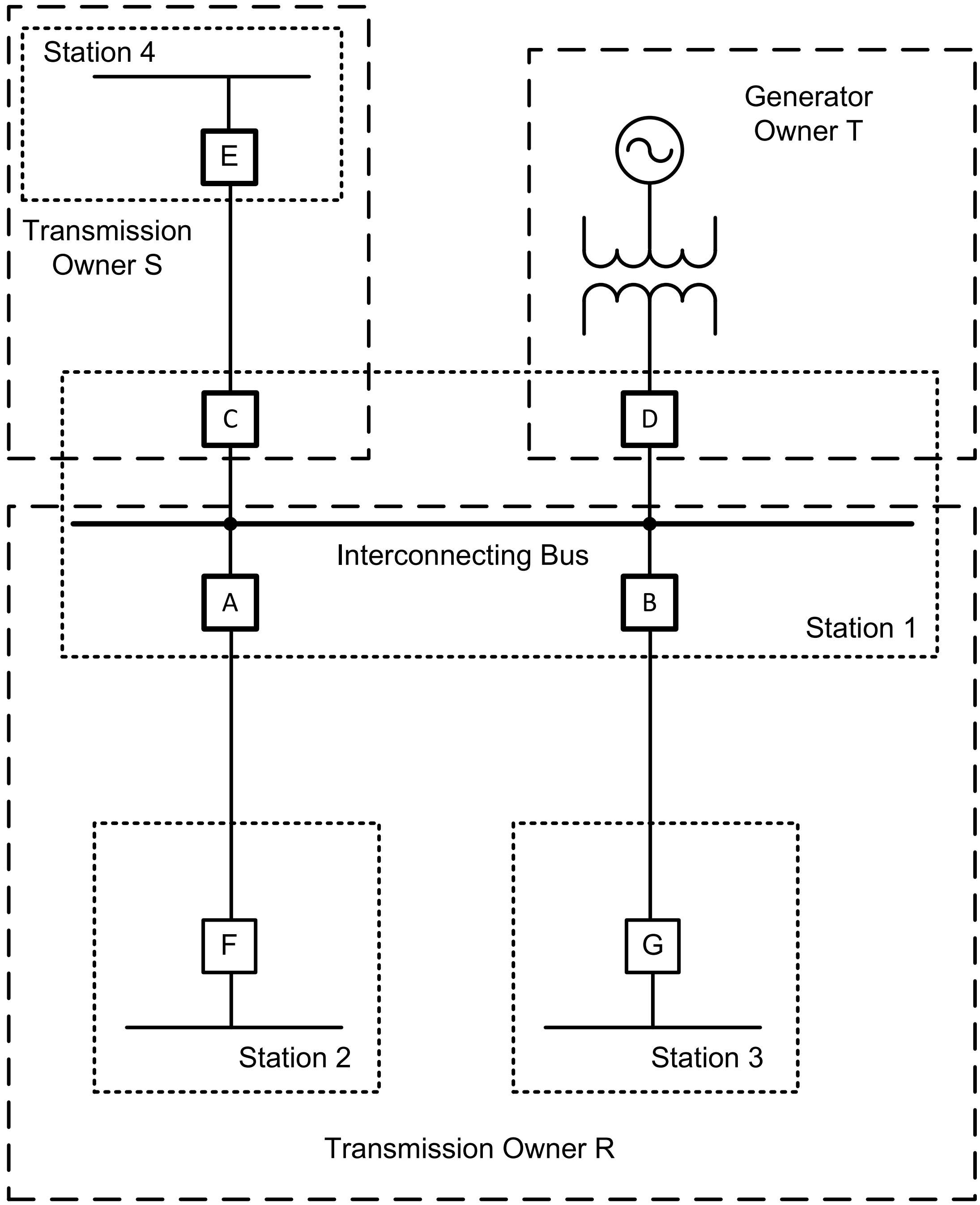
In Figure 4 above, the Interconnected Element between the Transmission Owner and the Distribution Provider is the transmission line or tap between the line and Breaker C.

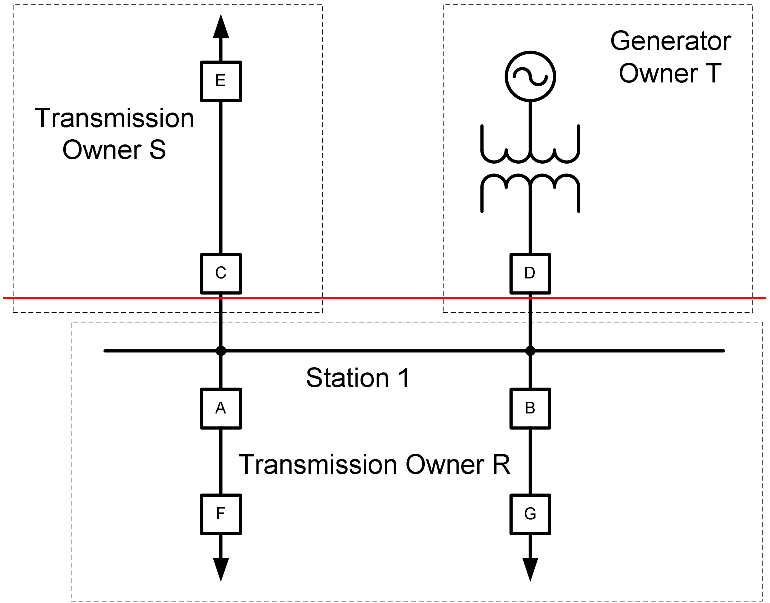
Note: No specific ~~Protection System Study~~PSCS is required per this standard for this example since the Protection System at the Distribution Provider's substation is not ~~designed to protect~~installed for the purpose of detecting Faults on BES ~~transmission system~~ Elements.

Figure 5

Transmission/Generation Facility with Multiple Owners

Note: In a large majority of cases, Figure 2 would be applicable for most generator interconnections. In Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T.


Station 4
E
Transmission
Owner S
Generator
Owner T
C
D
Interconnecting Bus
A
B
Station 1
F
G
Station 2
Station 3
Transmission Owner R



In Figure 5 above, the Interconnected Element between the Transmission Owners R and S and ~~the Generation~~Generator Owner T is the common Transmission bus. In this example, Transmission Owner S and Generator Owner T are not directly interconnected to each other at ~~Transmission~~ Station 1~~, and all~~. All direct interconnections are between Owner R and each of the other Owners connected to the common bus at Station 1.

Example: For the purposes of conducting the ~~Protection System Study~~PSCS associated with the Facilities in Figure 5:

Owner S is to develop proposed Protection System settings associated with Breakers C and E.

Owner T is to develop proposed Protection System settings associated with Breaker D, the generator, and its associated equipment.

Owner R is to develop proposed Protection System settings associated with Breakers A, B, F and G.

Owner R is to review the Protection System settings associated with Breaker C, E, D, and the generator Protection System (provided by Owners S and/or T) for coordination issues with the Protection System settings associated with Breakers A~~,~~ and B.

Owner S is to review the Protection System settings associated with Breakers A, F, B, G, D, and the generator Protection System (provided by Owners R and/or T) for coordination issues with the Protection System settings associated with Breaker C. To perform this review, it will be necessary that Transmission Owner R provide Owner S with its settings for Breakers A, F, B, and G, as well as the settings for Breaker D and generator Protection System settings provided to Owner R by Generator Owner T.

Owner T is to review the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R and/or S) for coordination issues with the Protection System settings associated with Breaker D or the ~~Protection Systems associated with~~ generator Protection System~~s~~. In order to perform this review, it will be necessary that Transmission Owner R provide Generator Owner T with its settings for Breakers A, F, G, and B, as well as the settings for Breaker C and E provided to Owner R by Transmission Owner S.

Unofficial Comment Form

Project 2007-06 System Protection Coordination
3rd Draft of PRC-027-1

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the 3rd draft of the standard PRC-027-1: Protection System Coordination for Performance During Faults. Comments must be submitted by **8 p.m. Eastern July 3, 2013**. If you have questions please contact Al McMeekin or by telephone at 803-530-1963.

http://www.nerc.com/pa/Stand/Pages/Project-2007-06-System-Protection-Coordination.aspx

Background Information:

The Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted an initial draft of the Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPCSDT attempted to address the planning and non-operational issues identified in the assessment of PRC-001-1 performed by the NERC System Protection and Control Task Force (SPCTF) as well as the operating time frame issues identified in FERC Order 693. These operating time frame requirements involved detecting Protection System failures, informing operators and taking quick corrective actions; consequently, the SPCSDT transferred the Order 693 directives associated with Requirements R2, R5 and R6 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standards associated within that project. The Project 2007-03 drafting team retired Requirements R2, R5, and R6 of PRC-001-1 because they addressed data and data requirements that are now included in Reliability Standard TOP-003-2. The NERC Board of Trustees adopted Reliability Standards TOP-003-2 and PRC-001-2 on May 9, 2012.

The SPCSDT has also revised PRC-001-2. Revisions include the removal of Requirements R2 and R3 (formerly Requirements R3 and R4 of PRC-001-1). These two legacy requirements are being retired because the aspects of coordination they address are incorporated in the proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The SPCSDT believes the training aspects of Requirement R1 would be more appropriately addressed by the PER group of Reliability Standards. Consequently, the drafting team has recommended via the NERC Issues Database that the future drafting team charged with revising PER-005-1 incorporate the reliability objective of Requirement R1 into the revised standard. Until that occurs, Requirement R1 of PRC-001-2 must remain in the standard. In an effort to improve PRC-001-2 until it can be fully retired, the drafting team has provided a measure to accompany Requirement R1. The Applicability section was also updated to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)

The SPCSDT has responded to stakeholder comments and incorporated pertinent suggestions into the third draft of PRC-027-1 for stakeholder review and comment. PRC-001-3 is also presented for your review.

Questions

For questions 1 – 7, please provide specific comments related to the individual question. For question 8, please provide general comments not related to questions 1 – 7.

You do not have to answer all questions. Enter All Comments in Simple Text Format. *Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. Based on stakeholder comments, the drafting team modified the Purpose of this standard to:

   "To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults."

   Do you agree with this Purpose? If not, please provide specific suggestions for improvement in the comment area.

   ☐ Yes

   ☐ No

   Comments:

2. The drafting team modified the proposed definition of **Interconnected Element** to read as follows:

   Interconnected Element: A BES Element that electrically joins facilities owned by:
   a) separate Registered Entities, or
   b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

   Do you agree with the revised definition? If not please provide specific suggestions for improvement in the comment area.

   ☐ Yes

   ☐ No

   Comments:

3. In Requirement R1, the drafting team modified the time frame to allow entities 60 months to have a documented Protection System Coordination Study (PSCS) completed for each Interconnected Element if no PSCS exists. Note, the drafting team has allowed inclusion of all previously performed PSCS whose summary of results include, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed.

Do you agree with this revised time frame? If not, please provide specific suggestions for change in the comment area.

☐ Yes

☐ No

Comments:

4. In Requirement R2, the drafting team modified the time frame to 60 months for either conducting a Fault current review or provide a technical justification as to why a Fault current review is not necessary.

   Do you agree with this revision to Requirement R2? If not, please provide specific suggestions for improvement in the comment area.

   ☐ Yes

   ☐ No

   Comments:

5. In Requirement R4, the drafting team has clarified the expectation of what a response to a review of the summary results of a Protection System Coordination Study should include. The options are as follows:

   - Accepting the results, or
   - Rejecting the results and suggesting modifications to resolve any identified coordination issues.

   Do you agree with this revision to Requirement R4? If not, please provide specific suggestions for improvement in the comment area.

   ☐ Yes

   ☐ No

   Comments:

6. The drafting team revised the Applicability section of PRC-001-2 to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.) Do you agree with this revision to the Applicability? If not, please provide specific suggestions for improvement in the comment area.

   ☐ Yes

   ☐ No

   Comments:

7. The drafting team provided a measure to accompany Requirement R1 of PRC-001-2. (The language in the measure was modeled after the existing language in the RSAW for PRC-001-2.) Do you agree with this measure? If not, please provide specific suggestions for improvement in the comment area.

   ☐ Yes

   ☐ No

   Comments:

8. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

   Comments:

Project 2007-06 System Protection Coordination Mapping Document

Mapping Document Showing Translation of PRC-001-2 – System Protection Coordination to PRC-027-1 – Protection System Coordination for Performance During Faults

Updated 10-31 to reflect changes made to requirements

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	Retained	NA
R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R2.1** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.	PRC-027-1, R1, R3, & R4 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Study (PSCS) for each of its Interconnected Element on its System as follows: **1.1.3.** According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or within six calendar months of being notified of a change as described in Part 3.3, or technically justify why

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
R2.2 Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.		such a study is not required. **1.2.** Within 90 calendar days after the completion of each PSCS provide to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s), a summary of the results of each PSCS performed pursuant to Requirement R1, Part 1.1, (including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed). **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnected Element: **3.1.** Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnected Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s). • New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios • Changes to a transmission system Element that alter any sequence

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		or mutual coupling impedance • Changes to generator unit(s) that result in a change in impedance • Changes to the generator step-up transformer(s) that result in a change in impedance **3.2.** Requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 calendar days of receiving a request or according to an agreed-upon schedule. **3.3.** Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components**.** **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **4.2.** Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.
R3. Each Transmission Operator shall	PRC-027-1,	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	R1, R2, R3, & R4 Note: Applicability changed to GO, TO and DP	shall: **1.1.** Perform a PSCS for each of its Interconnected Element on its System as follows: **1.1.1.** Within 60 calendar months after the effective date of this standard, if no PSCS for that Interconnected Element exists. **1.1.2.** Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. **1.2.** Within 90 calendar days after the completion of each PSCS provide to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s), a summary of the results of each PSCS performed pursuant to Requirement R1, Part 1.1, (including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed). **R2.** For each Interconnected Element on its System, the Transmission Owner shall, once every 60 calendar months, technically justify why Fault current does not affect the Protection System coordination, or: **2.1.** Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		interconnecting bus where a Protection System Coordination Study (PSCS) is available per Requirement R1. **2.2.** Calculate the percent change between the Fault current values (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation: Where : I_{scs} = Fault current value from present short circuit study And: I_{pscs} = Fault current value used in the most recent PSCS **2.2.1** Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (I_{scs}) to each owner of the Protection System associated with the Interconnected Element. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnected Element: **3.2.** Requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 calendar

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		days of receiving a request or according to an agreed-upon schedule. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **4.1.** Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a PSCS (per Requirement R1, Part 1.2) and respond to the other owner(s): • Accepting the results, or • Rejecting the results and suggesting modifications to resolve any identified coordination issues.

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Project 2007-06 System Protection Coordination Mapping Document

Mapping Document Showing Translation of PRC-001-2 – System Protection Coordination to PRC-027-1 – Protection System Coordination for Performance During Faults
Updated 10-31 to reflect changes made to requirements

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	Retained	NA
R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R2.1** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.	PRC-027-1, R1, R3, & R4 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Study (PSCS) for each of its Interconnected Element on its System as follows: **1.1.3.** According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 ~~or~~, or within six calendar months of being notified of a change as described in Part 3.3, or technically justify why

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
R2.2 Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.		such a study is not required. **1.2.** Within 90 calendar days after the completion of each ~~Protection System Study~~PSCS provide to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s~~)~~), a summary of the results of each ~~Protection System Study~~PSCS performed pursuant to ~~this requirement~~Requirement R1, Part 1.1, (including, at a minimum, the ~~protective relay settings~~Protection Systems reviewed, ~~power system Elements to be isolated, contingencies evaluated,~~the associated Fault currents used, any issues identified, and any revisions or actions proposed). **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnected Element: **3.1.** Details for any proposed change or ~~additions~~addition listed below; either at an existing or new Facility associated with the Interconnected Element; or at other ~~facilities~~Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s). • New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		transformer ratios • Changes to a transmission system Element that ~~change~~alter any sequence or mutual coupling impedance • Changes to generator unit(s) that result in a change in impedance • Changes to the generator step-up transformer(s) that result in a change in impedance **3.2.** Requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 calendar days of receiving a request or according to an agreed-upon schedule. **3.3.** Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components**.** **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **4.2.** Prior to implementing any ~~planned~~proposed change(s) or modifications associated with Requirement R3, Part 3.1~~, confirm the~~ or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element ~~accept any~~

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		~~resulting~~have accepted the Protection System(s) changes including the resolution of any identified coordination issues.
R3. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	PRC-027-1, R1, R2, R3, & R4 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a ~~Protection System Study~~PSCS for each of its Interconnected Element on its System as follows: **1.1.1.** Within ~~48~~60 calendar months after the effective date of this standard, if no ~~Protection System Study~~PSCS for that Interconnected Element exists. **1.1.2.** Within ~~six~~12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. **1.2.** Within 90 calendar days after the completion of each ~~Protection System Study~~PSCS provide to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s~~)~~), a summary of the results of each ~~Protection System Study~~PSCS performed pursuant to ~~this requirement~~Requirement R1, Part 1.1, (including, at a minimum, the ~~protective relay settings~~Protection Systems reviewed, ~~power system Elements to be isolated, contingencies evaluated,~~the associated Fault currents used, any issues identified, and any revisions or actions

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		proposed). **R2.** For each ~~Facility associated with an~~ Interconnected Element on its System, the Transmission Owner shall~~:~~ ~~2.1. At least~~, once every ~~24~~60 calendar months, technically justify why Fault current does not affect the Protection System coordination, or: **2.1.~~1~~** Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Coordination Study (PSCS) is available per Requirement R1. **2.~~1.~~2.** Calculate the percent ~~deviation~~change between the Fault current values (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent ~~Protection System Study~~PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.~~1~~.1, using the following equation: Where: I_{SCS} = Fault current value from present short-circuit study And: ~~I_{pss} =~~ I_{PSCS} = Fault current value used in the most recent ~~Protection System Study~~PSCS

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		2.2.1 ~~2.2.~~ Within 30 calendar days after identification ~~where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates~~of a ~~deviation in Fault current~~change of 10% or greater in either single line to ground or 3-phase Fault current, provide ~~each~~ the updated Fault current values (I_{SCS}) to each owner of the Protection System associated with the Interconnected Element ~~the updated Fault current values (Iscs).~~. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each ~~Responsible Entity~~Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnected Element: **3.2.** Requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 calendar days of receiving a request or according to an agreed-upon schedule. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **4.1.** Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a ~~Protection System Study, as described in~~PSCS (per Requirement R1, Part 1.2~~,~~) and respond ~~as~~ to ~~whether further action is required~~the other owner(s):

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		• Accepting the results, or • Rejecting the results and suggesting modifications to resolve any identified coordination issues.

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Implementation Plan

Project 2007-06 System Protection Coordination
PRC-027-1

Approvals Requested

- PRC-027-1 Protection System Coordination for Performance During Faults
- PRC-001-3 System Protection Coordination

Applicable Entities

Standard	Applicable Entities					
	TO	GO	DP	TOP	GOP	BA
PRC-027-1: Protection System Coordination for Performance During Faults	X	X	X			
PRC-001-3: System Protection Coordination				X	X	X

Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definitions for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

Interconnected Element: A BES Element that electrically joins facilities owned by:
a) separate Registered Entities, or
b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

Protection System Coordination Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.

Background

On December 7, 2006, the NERC Planning Committee approved the assessment of Standard PRC-001-1 (System Protection Coordination) prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF asserted:

> *"The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In*

addressing the 'operating horizon, operations planning horizon, and planning horizon' protection coordination issues, the deficiencies in the current standard are magnified."

And further:

"The SPCTF… recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards."

The Standard Committee approved the Standard Authorization Request with modifications by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

With the development of the proposed Reliability Standard PRC-027-1, the Standard Drafting Team (SDT) for Project 2007-06 – System Protection Coordination, has followed the observations and recommendation of the NERC SPCTF assessment of PRC-001-1 which had six requirements. The SDT accomplishes this by:

1. Incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) and moving those requirements into a new standard (as recommended by the SPCTF assessment), focusing on the performance of Protection Systems during Faults.
2. Assigning responsibility for coordination of Protection Systems during Faults to the appropriate functional entities – the Protection System equipment owners, specifically: Transmission Owners, Generator Owners, and Distribution Providers.
3. Transferring the responsibility of addressing the three operating horizon Requirements R2, R5, and R6 of PRC-001-1 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standard(s) within that project. (The NERC Board of Trustees approved these changes proposed by the Project 2007-03 team when it approved PRC-001-2 on May 9, 2012.)
4. Leaving the legacy Requirement R1 of PRC-001-2 in PRC-001-3 (thereby not creating a reliability gap) until it is incorporated into a new or revised reliability standard.

   Note: The drafting team added Measure (M1) to PRC-001-3 related to Requirement R1.

Effective Date of New or Revised Standards and Definitions

PRC-027-1 - Protection System Coordination for Performance During Faults

PRC-027-1 shall become effective on the first day of the first calendar quarter that is 12 months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. For Interconnected Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.

PRC-001-3 – System Protection Coordination
Same effective date as PRC-027-1.

Effective Date for Definitions

The two proposed definitions (Interconnected Facilities and Protection System Coordination Study) shall become effective at the same time as PRC-027-1.

Retirement:

PRC-001-2 – Protection System Coordination shall be retired at midnight the day before PRC-001-3 becomes effective.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2007-06 System Protection Coordination
PRC-027-1

Approvals Requested

- PRC-027-1 Protection System Coordination for Performance During Faults
- PRC-001-3 System Protection Coordination

Applicable Entities

Standard	Applicable Entities					
	TO	GO	DP	TOP	GOP	BA
PRC-027-1: Protection System Coordination for Performance During Faults	X	X	X			
PRC-001-3: System Protection Coordination				X	X	X

Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definitions for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

Interconnected Element: ~~An~~A BES Element that electrically joins facilities owned by:
a) separate ~~Functional~~Registered Entities, ~~including those Functional Entities that are a part of~~or
b) the same Registered Entity~~.~~ that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

Protection System Coordination Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults.

Background

On December 7, 2006, the NERC Planning Committee approved the assessment of Standard PRC-001-1 (System Protection Coordination) prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF asserted:

> *"The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In*

addressing the 'operating horizon, operations planning horizon, and planning horizon' protection coordination issues, the deficiencies in the current standard are magnified."

And further:

"The SPCTF… recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards."

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With the development of the proposed Reliability Standard PRC-027-1, the Standard Drafting Team (SDT) for Project 2007-06 – System Protection Coordination, has followed the observations and recommendation of the NERC SPCTF assessment of PRC-001-1 which had six requirements. The SDT accomplishes this by:

1. Incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) and moving those requirements into a new standard (as recommended by the SPCTF assessment), focusing on the performance of Protection Systems during Faults.
2. Assigning responsibility for coordination of Protection Systems during Faults to the appropriate functional entities – the Protection System equipment owners, specifically: Transmission Owners, Generator Owners, and Distribution Providers.
3. Transferring the responsibility of addressing the three operating horizon Requirements R2, R5, and R6 of PRC-001-1 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standard(s) within that project. (The NERC Board of Trustees approved these changes proposed by the Project 2007-03 team when it approved PRC-001-2 on May 9, 2012.)
4. Leaving the legacy Requirement R1 of PRC-001-2 in PRC-001-3 (thereby not creating a reliability gap) until it is incorporated into a new or revised reliability standard.

   Note: The drafting team added Measure (M1) to PRC-001-3 related to Requirement R1.

Effective Date of New or Revised Standards and Definitions

PRC-027-1 - Protection System Coordination for Performance During Faults

PRC-027-1 shall become effective on the first day of the first calendar quarter that is ~~six~~12 months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is ~~six~~12 months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. For Interconnected Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.

PRC-001-3 – System Protection Coordination
Same effective date as PRC-027-1.

Effective Date for Definitions

The two proposed definitions (Interconnected Facilities and Protection System Coordination Study) shall become effective at the same time as PRC-027-1.

Retirement:

PRC-001-2 – Protection System Coordination shall be retired at midnight the day before PRC-001-3 becomes effective.

Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 — Protection System Coordination for Performance During Faults

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1 — Protection System Coordination for Performance During Faults.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

The System Protection Coordination Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors
High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures; nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.
In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and, therefore, concentrated its approach on the reliability impact of the requirements.

PRC-027-1 Protection System Coordination for Performance During Faults is a new Reliability Standard with the stated purpose: "*To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.*" PRC-027-1 has four (4) requirements that incorporate and clarify the reliability intent of Requirements R3 and R4 of PRC-001-1. The new standard addresses the aspects of coordination for new and changes to existing Protection Systems, as well as requiring an initial and periodic review of existing Protection Systems. The new requirements describe the steps necessary to achieve coordination. The coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner, reviewing each others' Protection System settings and schemes, and resolving any identified coordination issues.

All four requirements are assigned VRFs of Medium. The assignment of the Medium VRFs was made based on the premise that failure to perform these coordination activities by themselves would not directly cause or contribute to bulk power system instability, separation, or a Cascading sequence of failures. For a requirement to be assigned a "High" VRF, there should be the expectation that failure to meet the required performance "will" result in instability, separation, or Cascading failures, and this is usually not the case when an applicable entity fails to 'coordinate' activities. While the SDT agrees that, under some circumstances, it is possible that a failure to perform the required activities may hinder the coordination process; however, the failure would not, by itself, result in instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-027-1, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to perform a Protection System Coordination Study for each Interconnected Element to verify that Protection Systems components operate in the desired sequence during Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R1 is similar in scope to Requirements R2, R3 and R4, as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R1 directs that Protection System Coordination Studies are performed for every Interconnected Element to verify coordination of existing Protection Systems. This requirement is similar to Requirement R1 of FAC-002-1, which also requires studies be performed and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to perform a Protection System Coordination Study for each Interconnected Facility to verify that Protection Systems components operate in the desired sequence during Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R1 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by less than or equal to 10 calendar days.	The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days	The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required but was late by more than 60 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar days. OR

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
			The responsible entity failed to perform a Protection System Coordination Study on an Interconnected Element in accordance with Requirement R1, Parts 1.1.1, 1.1.2, or 1.1.3. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2 or 1.1.3. OR The responsible entity failed to provide Protection System Coordination Study results in accordance with Requirement R1, Part 1.2.

VSL Justifications – PRC-027-1, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to periodically justify why Fault current does not affect the Protection System coordination; or perform a short circuit study, calculate the percent change in Fault current values used as inputs for updating Protection System Coordination Study(s), and to provide each owner of the Protection System associated with the Interconnected Element of requisite changes in Fault currents, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R2 is similar in scope to Requirements R1, R3 and R4, as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R2 facilitates a periodic review of technical justifications or Fault currents, and notification of owner(s) of the Protection System(s) associated with the Interconnected Element(s). This requirement is similar to Requirement R6 of BAL-005-0.2b in that it also requires the comparison of calculated data and possible notification of other entities; and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to periodically justify why Fault current does not affect Protection System Coordination; or perform a short circuit study, calculate the percent change in Fault current values used as inputs for updating Protection System Coordination Study(s) and to provide each owner of the Protection System associated with the Interconnected Element of requisite deviations in Fault currents, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R2 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R2			
Lower	**Moderate**	**High**	**Severe**
For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by less than or equal to 30 calendar days. OR The Transmission Owner performed a short circuit study, as required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days. OR The Transmission Owner provided the	For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The Transmission Owner provided the	For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The Transmission Owner provided the	For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 90 calendar days. OR The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 90 calendar days. OR The Transmission Owner failed to perform a short circuit study, as required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent change between the Fault currents, according to the equation designated in Requirement R2, Part 2.2. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as required in Requirement R2, Part

Proposed VSLs for PRC-027-1, R2			
Lower	**Moderate**	**High**	**Severe**
owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	owner(s) of the Facility associated with the Interconnected Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnected Element, the updated Fault current values, as required in Requirement R2, Part 2.2.1.

VSL Justifications – PRC-027-1, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to communicate proposed changes that modify the conditions used in the coordination of Protection Systems associated with an Interconnected Element or provide requested information needed to conduct a Protection System Coordination Study could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R3 is similar in scope to Requirements R1, R2 and R4 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R3 facilitates the provision of pertinent information regarding proposed changes that could impact the coordination of Protection Systems associated with an Interconnected Element, or information needed to do a Protection System Coordination Study. This requirement is similar to Requirement R2 of FAC-009-1 in that it also requires the provision of reliability data to other pertinent functional entities, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to communicate proposed changes that modify the conditions used in the coordination of Protection Systems associated with an Interconnected Element or provide requested information needed to conduct a Protection System Coordination Study could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R3 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R3			
Lower	**Moderate**	**High**	**Severe**
The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity failed to provide the owner(s) of the Facility associated with the Interconnected Element, details for any proposed change or addition identified in Requirement R3, Part 3.1. OR The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the information required in Requirement R3, Part 3.3.

VSL Justifications – PRC-027-1, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to communicate and cooperate with the other owners of the Protection System(s) to resolve coordination issues associated with an Interconnected Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R4 is similar in scope to Requirements R1, R2 and R3 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R4 mandates responsible entities affirm acceptance on Protection System Study results or proposed changes to Protection System(s) prior to implementation. This requirement is similar to Requirement R2 of PRC-023-1 in that it also requires agreement be obtained, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to communicate and cooperate with the other owners of the Protection System(s) to resolve coordination issues associated with an Interconnected Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R4 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.	The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.	The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1.	The responsible entity responded in more than 120 calendar days following the receipt of the summary results of the Protection System Coordination Study, as required in Requirement R4, Part 4.1. OR The responsible entity failed to review the summary results of the Protection System Coordination Study provided to them in accordance with Requirement R4, Part 4.1. OR The responsible entity failed to respond to the other owners in accordance with Requirement R4, Part 4.1. OR The responsible entity failed to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element accepted the Protection System(s) changes including the resolution of any identified coordination issues, prior to implementation

Proposed VSLs for PRC-027-1, R4			
Lower	**Moderate**	**High**	**Severe**
			of those changes, as required in Requirement R4, Part 4.2.

VSL Justifications – PRC-027-1, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 — Protection System Coordination for Performance During Faults

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1 — Protection System Coordination for Performance During Faults.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

The System Protection Coordination Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures; nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and, therefore, concentrated its approach on the reliability impact of the requirements.

PRC-027-1 Protection System Coordination for Performance During Faults is a new Reliability Standard with the stated purpose: "*To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.*" PRC-027-1 has four (4) requirements that incorporate and ~~enhance~~clarify the reliability intent of Requirements R3 and R4 of PRC-001-1. The new standard addresses the aspects of coordination for new and changes to existing Protection Systems, as well as ~~changes to~~requiring an initial and periodic review of existing Protection Systems. The new requirements describe the steps necessary to achieve coordination. The coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner, ~~and confirming acceptance of~~reviewing each others' Protection System settings and schemes, and resolving any identified coordination issues.

All four requirements are assigned VRFs of Medium. The assignment of the Medium VRFs was made based on the premise that failure to perform these coordination activities by themselves would not directly cause or contribute to bulk power system instability, separation, or a Cascading sequence of failures. For a requirement to be assigned a "High" VRF, there should be the expectation that failure to meet the required performance "will" result in instability, separation, or Cascading failures, and this is usually not the case when an applicable entity fails to 'coordinate' activities. While the SDT agrees that, under some circumstances, it is possible that a failure to perform the required activities may hinder the coordination process; however, the failure would not, by itself, result in instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-027-1, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to perform a Protection System Coordination Study for each Interconnected Element to verify that Protection Systems ~~coordinate such that~~components operate in the ~~least number of power system Elements are isolated to clear~~desired sequence during Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R1 is similar in scope to Requirements R2, R3 and R4, as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R1 directs that Protection System Coordination Studies are performed for every Interconnected Element to verify coordination of existing Protection Systems. This requirement is similar to Requirement R1 of FAC-002-1, which also requires studies be performed and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to perform a Protection System Coordination Study for each Interconnected Facility to verify that Protection Systems ~~coordinate such that~~components operate in the ~~least number of power system Elements are isolated to clear~~desired sequence during Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R1 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed a Protection System Coordination Study on an Interconnected Element ~~per~~as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus ~~per~~as required in Requirement R1, Part 1.1.2, or ~~documented~~technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by less than or equal to 10 calendar days ~~or less~~.	The responsible entity performed a Protection System Coordination Study on an Interconnected Element ~~per~~as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus ~~per~~as required in Requirement R1, Part 1.1.2, or ~~documented~~technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to ~~40~~45 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or	The responsible entity performed a Protection System Coordination Study ~~at~~on an ~~interconnecting bus per~~Interconnected Element as required in Requirement R1, Part 1.1.~~2, or documented why a study was not required~~1, but was late by more than ~~40~~60 calendar days but less than or equal to ~~50~~90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Part 1.1.2, or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by	The responsible entity performed a Protection System Coordination Study on an Interconnected Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus ~~per~~as required in Requirement R1, Part 1.1.2, or ~~documented~~technically justified why a study was not required but was late by more than ~~50~~60 calendar days. OR The responsible entity provided the Protection System Coordination Study results in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar days.

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
	equal to 20 calendar days.	more than 20 calendar days but less than or equal to 30 calendar days~~.~~	OR The responsible entity failed to perform a Protection System Coordination Study on an Interconnected Element ~~per~~in accordance with Requirement R1, Parts 1.1.1, 1.1.2, or 1.1.3~~, or document why a study was not required~~. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2 or 1.1.3. OR The responsible entity failed to provide Protection System Coordination Study results in accordance with Requirement R1, Part 1.2.

VSL Justifications – PRC-027-1, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to periodically ~~review~~justify why Fault current does not affect the Protection System coordination; or perform a short circuit study, calculate the percent ~~deviation~~change in ~~f~~Fault current values used as inputs for updating Protection System Coordination Study(s), and to provide each owner of the Protection System associated with the Interconnected Element of requisite ~~deviations~~changes in ~~f~~Fault currents, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R2 is similar in scope to Requirements R1, R3 and R4, as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R2 facilitates a periodic review of technical justifications or Fault currents, and notification of owner(s) of the Protection System(s) associated with the Interconnected Element(s). This requirement is similar to Requirement R6 of BAL-005-0.2b in that it also requires the comparison of calculated data and possible notification of other entities; and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to periodically ~~review,~~justify why Fault current does not affect Protection System Coordination; or perform a short circuit study, calculate the percent ~~deviation~~change in ~~f~~Fault current values used as inputs for updating Protection System Coordination Study(s) and to provide each owner of the Protection System associated with the Interconnected Element of requisite deviations in ~~f~~Fault currents, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:

VRF Justifications – PRC-027-1, R2	
	PRC-027-1, Requirement R2 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R2			
Lower	**Moderate**	**High**	**Severe**
For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by less than or equal to 30 calendar days. OR The Transmission Owner performed a short circuit study, as ~~described~~required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days. OR The Transmission	For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The Transmission Owner performed a short circuit study as ~~described~~required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to ~~40~~60 calendar days. OR The Transmission	For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The Transmission Owner performed a short circuit study as ~~described~~required in Requirement R2, Part 2.1, but was late by more than ~~40~~60 calendar days but less than or equal to ~~50~~90 calendar days. OR The Transmission	~~The~~ For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 90 calendar days. OR The Transmission Owner performed a short circuit study as ~~described~~required in Requirement R2, Part 2.1, but was late by more than ~~50~~90 calendar days. OR The Transmission Owner failed to perform a short circuit study, as ~~described~~required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent ~~deviation~~change between the Fault currents, according to the ~~formula~~equation designated in Requirement R2, Part 2.2. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnected

Proposed VSLs for PRC-027-1, R2			
Lower	**Moderate**	**High**	**Severe**
Owner provided the owner(s) of the Facility associated with the Interconnected Element ~~of~~, the changes in Fault currents, as ~~described~~required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	Owner provided the owner(s) of the Facility associated with the Interconnected Element ~~of~~, the changes in Fault currents, as ~~described~~required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	Owner provided the owner(s) of the Facility associated with the Interconnected Element ~~of~~, the changes in Fault currents, as ~~described~~required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	Element ~~of~~, the changes in Fault currents, as ~~described~~required in Requirement R2, Part 2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnected Element, the ~~changes in~~updated Fault ~~currents~~current values, as required in Requirement R2, Part 2.2.1.

VSL Justifications – PRC-027-1, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to communicate proposed changes that modify the conditions used in the coordination of Protection Systems associated with an Interconnected Element or provide requested information needed to conduct a Protection System Coordination Study could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R3 is similar in scope to Requirements R1, R2 and R4 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R3 facilitates the provision of pertinent information regarding proposed changes that could impact the coordination of Protection Systems associated with an Interconnected Element~~.~~, or information needed to do a Protection System Coordination Study. This requirement is similar to Requirement R2 of FAC-009-1 in that it also requires the provision of reliability data to other pertinent functional entities, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to communicate proposed changes that modify the conditions used in the coordination of Protection Systems associated with an Interconnected Element or provide requested information needed to conduct a Protection System Coordination Study could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R3 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R3			
Lower	**Moderate**	**High**	**Severe**
The responsible entity provided the requested information ~~per~~required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days~~ or less.~~. OR The responsible entity provided the ~~required~~ information ~~identified~~required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days~~ or less~~.	The responsible entity provided the requested information ~~per~~required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the ~~required~~ information ~~identified~~required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information ~~per~~required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the ~~required~~ information ~~identified~~required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity failed to provide ~~information to~~ the owner(s) of the Facility associated with the Interconnected Element, details for any proposed change or addition identified in Requirement R3, Part 3.1. OR The responsible entity provided the requested information ~~per~~required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the ~~required~~ information ~~identified~~required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the ~~requested~~ information required in Requirement R3, Part 3.3.

VSL Justifications – PRC-027-1, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to ~~confirm acceptance for proposed changes that modify the~~communicate and cooperate with the ~~conditions used in~~ other owners of the ~~coordination of~~ Protection System(s) to resolve coordination issues associated with ~~the~~an Interconnected Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R4 is similar in scope to Requirements R1, R2 and R3 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R4 mandates responsible entities ~~con~~affirm acceptance on Protection System Study results or proposed changes to Protection System(s) prior to implementation. This requirement is similar to Requirement R2 of PRC-023-1 in that it also requires agreement be obtained, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to ~~confirm acceptance for proposed changes that modify the~~communicate and cooperate with the ~~conditions used in~~ other owners of the ~~coordination of~~ Protection System(s) to resolve coordination issues associated with ~~the~~an Interconnected Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. ~~Therefore, this Violation Risk Factor level conforms to~~This requirement meets NERC's ~~definition of~~criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R4 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity ~~confirmed acceptance~~responded in more than 90 calendar days but less than or equal to 100 calendar days following the receipt of the summary results of the Protection System Coordination Study ~~per~~, as required in Requirement R4, Part 4.1~~, but was late by 10 calendar days or less.~~ .	The responsible entity ~~confirmed acceptance~~responded in more than 100 calendar days but less than or equal to 110 calendar days following the receipt of the summary results of the Protection System Coordination Study ~~per~~, as required in Requirement R4, Part 4.1~~, but was late by more than 10 calendar days but less than or equal to 20 calendar days.~~ .	The responsible entity ~~confirmed acceptance~~responded in more than 110 calendar days but less than or equal to 120 calendar days following the receipt of the summary results of the Protection System Coordination Study ~~per~~, as required in Requirement R4, Part 4.1~~, but was late by more than 20 calendar days but less than or equal to 30 calendar days.~~ .	The responsible entity ~~confirmed acceptance~~responded in more than 120 calendar days following the receipt of the summary results of the Protection System Coordination Study ~~per~~, as required in Requirement R4, Part 4.1~~, but was late by more than 30 calendar days~~. OR The responsible entity failed to ~~confirm acceptance of~~review the summary results of the Protection System Coordination Study ~~per~~provided to them in accordance with Requirement R4, Part 4.1. OR The responsible entity failed to ~~confirm acceptance of the planned~~respond to the other owners in accordance with Requirement R4, Part 4.1. OR The responsible entity failed to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element

Proposed VSLs for PRC-027-1, R4			
Lower	**Moderate**	**High**	**Severe**
			accepted the Protection System(s) changes ~~pursuant to R4, Part 4.2~~including the resolution of any identified coordination issues, prior to implementation of those changes, as required in Requirement R4, Part 4.2.

VSL Justifications – PRC-027-1, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

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Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Successive Ballot and Non-Binding Poll now open through July 3, 2013

Now Available

A successive ballot of **PRC-027-1** – System Protection Coordination for Performance During Faults and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is now being conducted through **8 p.m. Eastern on Wednesday, July 3, 2013**.

Background information for this project can be found on the project page.

Instructions
Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps
The ballot results for **PRC-027-1** will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Formal Comment Period: June 4, 2013 – July 3, 2013

Upcoming:
Successive Ballot and Non-Binding Poll Open for PRC-027-1: June 24, 2013 – July 3, 2013

Now Available

A 30-day formal comment period is open for **PRC-027-1** – Protection System Coordination for Performance During Faults through **8 p.m. Eastern on Wednesday, July 3, 2013**.

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period for **PRC-027-1** is open through **8 p.m. Eastern on Wednesday, July 3, 2013.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

A successive ballot of **PRC-027-1** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted from June 24, 2013 through July 3, 2013.

Standards Development Process

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Standards Announcement

Project 2007-06 System Protection Coordination PRC-027-1

Successive Ballot and Non-Binding Poll Results

Now Available

A successive ballot of **PRC-027-1** – System Protection Coordination for Performance During Faults and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) concluded at **8 p.m. Eastern on Wednesday, July 3, 2013**.

Approval	Non-binding Poll Results
Quorum: 77.65% Approval: 52.71%	Quorum: 77.12% Supportive Opinions: 52.48%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Ballot Results	
Ballot Name:	Project 2007-06 Successive Ballot PRC-027-1
Ballot Period:	6/24/2013 - 7/3/2013
Ballot Type:	Successive Ballot
Total # Votes:	330
Total Ballot Pool:	425
Quorum:	**77.65 % The Quorum has been reached**
Weighted Segment Vote:	52.71 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	114	1	45	0.556	36	0.444	11	22
2 - Segment 2.	9	0.7	4	0.4	3	0.3	0	2
3 - Segment 3.	102	1	40	0.548	33	0.452	7	22
4 - Segment 4.	37	1	8	0.333	16	0.667	3	10
5 - Segment 5.	88	1	26	0.413	37	0.587	7	18
6 - Segment 6.	52	1	19	0.487	20	0.513	2	11
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	9	0.5	4	0.4	1	0.1	0	4
9 - Segment 9.	6	0.2	0	0	2	0.2	0	4
10 - Segment 10.	8	0.5	5	0.5	0	0	1	2
Totals	**425**	**6.9**	**151**	**3.637**	**148**	**3.263**	**31**	**95**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	ATCO Electric	Glen Sutton	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Negative	

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	
1	City of Pasadena	Marco A Sustaita	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	City Water, Light & Power of Springfield	Shaun Anders		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Consumers Power Inc.	Stuart Sloan		
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis		
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	
1	JEA	Ted Hobson	Negative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	
1	Lee County Electric Cooperative	John W Delucca		
1	LG&E Energy Transmission Services	Bradley C. Young		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Abstain	
1	Metropolitan Water District of Southern California	Ernest Hahn		
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Negative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	

1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PacifiCorp	Ryan Millard	Affirmative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Brett A. Koelsch	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry G Akens	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	
1	Turlock Irrigation District	Esteban Martinez	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn		
1	Western Farmers Electric Coop.	Forrest Brock		
1	Wolverine Power Supply Coop., Inc.	Michelle Denike		
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley		
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Negative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Alameda Municipal Power	Douglas Draeger	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	
3	Basin Electric Power Cooperative	Daniel Klempel		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	Central Electric Power Cooperative	Adam M Weber	Negative	
3	Central Lincoln PUD	Steve Alexanderson	Negative	

3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Lodi, California	Elizabeth Kirkley	Affirmative	
3	City of Palo Alto	Eric R Scott	Affirmative	
3	City of Redding	Bill Hughes	Negative	
3	City of Ukiah	Colin Murphey	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers	Abstain	
3	Clearwater Power Co.	Dave Hagen		
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock		
3	Consumers Power Inc.	Roman Gillen		
3	Coos-Curry Electric Cooperative, Inc	Roger Meader		
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger	Abstain	
3	Fall River Rural Electric Cooperative	Bryan Case		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter	Negative	
3	Lane Electric Cooperative, Inc.	Rick Crinklaw		
3	Lincoln Electric System	Jason Fortik	Negative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Northern Lights Inc.	Jon Shelby		
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Pacific Northwest Generating Cooperative	Rick Paschall		
3	PacifiCorp	Dan Zollner	Affirmative	
3	Pepco Holdings, Inc.	Mark R Jones		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	

3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Negative	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Raft River Rural Electric Cooperative	Heber Carpenter		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salmon River Electric Cooperative	Ken Dizes	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Umatilla Electric Cooperative	Steve Eldrige		
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	
4	Central Lincoln PUD	Shamus J Gamache	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Negative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Pacific Northwest Generating Cooperative	Aleka K Scott		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Southern Minnesota Municipal Power Agency	Richard L Koch		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Turlock Irrigation District	Steven C Hill		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
4	WPPI Energy	Todd Komplin	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Abstain	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	

5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Negative	
5	City of Tallahassee	Karen Webb	Negative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer		
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne		
5	Imperial Irrigation District	Marcela Y Caballero		
5	Invenergy LLC	Alan Beckham	Abstain	
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Negative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	

5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	WPPI Energy	Steven Leovy	Negative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Abstain	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Negative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil		
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Negative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina	Negative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II		

6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner		
8		Edward C Stein	Affirmative	
8	JDRJC Associates	Jim Cyrulewski		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan		
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	California Energy Commission	William M Chamberlain		
9	Central Lincoln PUD	Bruce Lovelin	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	Oregon Public Utility Commission	Jerome Murray		
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Midwest Reliability Organization	William S Smith		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito		
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Non-binding Results

Project 2007-06: PRC-027-1

Non-binding Poll Results	
Non-binding Poll Name:	Project 2007-06 Non-binding Poll PRC-027-1
Poll Period:	6/24/2013 - 7/3/2013
Total # Opinions:	300
Total Ballot Pool:	389
Summary Results:	77.12% of those who registered to participate provided an opinion or an abstention; 52.48% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	ATCO Electric	Glen Sutton	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	
1	City of Pasadena	Marco A Sustaita	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	City Water, Light & Power of Springfield	Shaun Anders		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	

1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis		
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Negative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	
1	Lee County Electric Cooperative	John W Delucca		
1	LG&E Energy Transmission Services	Bradley C. Young		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	

1	PacifiCorp	Ryan Millard	Abstain	
1	PECO Energy	Ronald Schloendorn		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Brett A. Koelsch	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Negative	
1	Turlock Irrigation District	Esteban Martinez	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn		
1	Western Farmers Electric Coop.	Forrest Brock		
1	Wolverine Power Supply Coop., Inc.	Michelle Denike		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley		
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Alameda Municipal Power	Douglas Draeger		
3	Ameren Services	Mark Peters	Abstain	

3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Basin Electric Power Cooperative	Daniel Klempel		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Lodi, California	Elizabeth Kirkley	Affirmative	
3	City of Palo Alto	Eric R Scott	Affirmative	
3	City of Redding	Bill Hughes	Negative	
3	City of Ukiah	Colin Murphey	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock		
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter	Negative	
3	Lincoln Electric System	Jason Fortik	Negative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	

3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salmon River Electric Cooperative	Ken Dizes	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Negative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	

NERC

4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Turlock Irrigation District	Steven C Hill		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
4	WPPI Energy	Todd Komplin	Negative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Edward Cambridge	Abstain	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Phillip Porter		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Negative	
5	City of Tallahassee	Karen Webb	Negative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	

5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer		
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky		
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne		
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Abstain	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	

5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	WPPI Energy	Steven Leovy	Negative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Abstain	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Negative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Duke Energy	Greg Cecil		
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson	Negative	
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Negative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried		
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		

6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	South California Edison Company	Lujuanna Medina	Negative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	
8		Edward C Stein	Affirmative	
8		James A Maenner		
8		Roger C Zaklukiewicz	Affirmative	
8	JDRJC Associates	Jim Cyrulewski		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	California Energy Commission	William M Chamberlain		
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Midwest Reliability Organization	William S Smith		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito		
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (67 Responses)
Name (41 Responses)
Organization (41 Responses)
Group Name (26 Responses)
Lead Contact (26 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (16 Responses)
Comments (67 Responses)
Question 1 (44 Responses)
Question 1 Comments (51 Responses)
Question 2 (45 Responses)
Question 2 Comments (51 Responses)
Question 3 (45 Responses)
Question 3 Comments (51 Responses)
Question 4 (43 Responses)
Question 4 Comments (51 Responses)
Question 5 (44 Responses)
Question 5 Comments (51 Responses)
Question 6 (39 Responses)
Question 6 Comments (51 Responses)
Question 7 (40 Responses)
Question 7 Comments (51 Responses)
Question 8 (0 Responses)
Question 8 Comments (51 Responses)

Group
Florida Municipal Power Agency
Frank Gaffney
No
FMPA continues to believe the greater purpose is to ensure faults are cleared within their critical clearing times and that such consideration is greater than operating within the desired sequence. The same comment would apply to the definition of Protection System Coordination Study.
No
The definition poses a problem with the second bullet. It is relatively easy to determine the "boundaries" between separate Registered Entities. It can be difficult to determine the boundaries between where an entity's separate registrations begin and end. Just look at how difficult determining the boundaries of the BES is, and witness the challenges of the GO/TO project where the boundaries between GO and TO are/were not clear. This standard now requires us to also draw the boundary between TO and DP. For example, let's take a step-down

transformer to distribution that is connected to a ring bus or breaker-and-a-half scheme. Typically, the high side relays for the transformer will be connected to the current transformers on the breaker bushings within the bus arrangement, which are part of the BES. Those relays are not only there to protect the transformer (not BES), but, also the bus section within the ring or breaker-and-a-half scheme (which is BES). So, are those relays (e.g., differential, directional overcurrent looking into the transformer) owned by the TO or DP registration? It also seems to FMPA that the reliability objective should not be limited to coordinating relays at just the "boundaries"; so, maybe one way to solve the boundary issue is to ignore it and just require a Registered Entity to coordinate its relays that protect the BES. This would expand the scope of the standard even more than the current PRC-001 to the proposed PRC-027, but, it would meet the reliability objective better. Another way to do it is to coordinate all at > 200 kV following PRC-023, and coordinate at the boundaries between entities (not registrations), at all BES.
No
Five (5) years seems way too long for an initial coordination study. We should pick a period of time that both industry and FERC will likely approve, maybe something like two (2) years. Other comments on R1: FMPA's interpretation of the Applicability combined with the standard is that remote back-up protection is included as it was "installed for the purpose of detecting Faults on Interconnected Elements". This becomes ambiguous for directional, inverse time ground current protection whose reach can vary with ground current, or with such relays and zone distance relays with changes in system configuration. FMPA's interpretation is that the Applicability is to the maximum reach of such relays; is that the intent of the SDT? Bullet 1.2 is ambiguous in its use of the term "owner"; especially in combination with the definition of Interconnected Element that makes the distinction between different registered functions within the same entity. Is the owner the entity, or the registered function? We assume the "owner" is the entity; is that the intent of the SDT?
Yes
No
Bullet 1.2 is ambiguous in its use of the term "owner"; especially in combination with the definition of Interconnected Element that makes the distinction between different registered functions within the same entity. Is the owner the entity, or the registered function? We assume the "owner" is the entity; is that the intent of the SDT?
Yes
Yes
Group
ISO RTO Council Standards Review Committee
Greg Campoli, Chair

No
It seems like the scope of the standard as stated in the purpose statement can be misunderstood. Later in the proposed standard, the purpose is narrowed: “Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1.” The SDT should consider revising the purpose to reflect the scope of this standard, e,g. “,,,operate in the desired sequence to CLEAR faults.” a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. This is a training requirement and as such, it should be transferred to the appropriate PER standards. The SRC supports the project for removing this requirement and moved into the PER standards..Providing training evidence does not demonstrate that the (operating personnel of) responsible entities are “familiar with” the purpose and limitations of protection system schemes applied in its area. c. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. In response to comment submitted by some commenters, the SDT indicates that it “…recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.” We do not agree with this recommendation and hold the view that adding the issue to the NERC Issue Data Base is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT should propose a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee’s advice/direction for appropriate actions. We do not believe that the SDT or staff has brought this to the Standards Committee’s attention. Note that the Standards Committee is responsible for managing the standards development process and as such, can make an informed decision to either request the SDT to expand its scope (via an amended SAR) to address the PRC-001 issue, or to ask staff or the SDT to prepare a separate SAR to address the issue in parallel. Leaving the PRC-001 hanging out there without a recourse is not a satisfactory solution, and may in fact harm reliability. We urge the SDT to take the initiative to bring this issue to the Standards Committee, with a proposal to amend the SAR or prepare a new SAR, or seek its advice and direction before continuing work on this project.]
Yes
Yes
SRC chooses not to respond to this question, please disregard the response as it was selected in error and could not be deleted.

Yes
SRC chooses not to respond to this question, please disregard the response as it was selected in error and could not be deleted.
No
R4 requires all affected parties to agree to a solution. However the applicable Functional Entities that PRC-027 impacts are limited only to the TO, GO and DP. When designing a protection system scheme to clear faults, a satisfactory solution in the prospective of a TO, GO and DP may have unintended consequences for the Transmission Operator. For example, what if the solution is to leave a significantly loaded transmission line in a potentially single end situation by leaving a ring bus configuration open after clearing a fault? How can the TO, GO and DP ensure their agreed upon solution is manageable for the Transmission Operator? Should there be a notification requirement to the TOP?
Yes
Yes
Individual
Dan Roethemeyer
Dynegy
Yes
No
•Please provide more examples of interconnected elements, especially for a merchant generator. It’s not clear if the protection system study should address protection systems for just the generator breaker or also the generator step up transformer, unit auxiliary transformer, or the generator itself. Perhaps this information belongs in the Application Guideline.
Yes
Yes
Yes
Yes
Yes

If a Generator Owner does not own a Protection System associated with an Interconnected Element, does the Standard apply? For instance, if the generator breaker opens only for faults on the Generator Owner side of the breaker (i.e., GSU or generator faults). Is it expected most GOs will own Protection Systems associated with an Interconnected Element?
Group
Northeast Power Coordinating Council
Guy Zito
No
The wording is redundant. Coordinating Protection Systems mean operating in the desired sequence during faults. The Purpose should just read "To coordinate Protection Systems for Interconnected Elements".
Yes
Yes
60 months is an adequate and appropriate period which balances the interest of reliability with the economics related to engineering costs.
Yes
60 months is an adequate and appropriate period which balances the interest of reliability with the economics related to engineering costs.
No
R4 requires all affected parties agree to a solution. However, the applicable Functional Entities that PRC-027 impacts are limited only to the TO, GO and DP. When designing a protection system scheme to clear faults, a satisfactory solution in the perspective of a TO, GO and DP may have unintended consequences for the Transmission Operator. For example, what if the solution is to leave what in normal operation is a significantly loaded transmission line in a potentially open terminal configuration by leaving a ring bus configuration open after clearing a fault? How can the TO, GO and DP ensure their agreed upon solution is manageable for the Transmission Operator? There should be a notification requirement to the TOP.
Yes
There should be consistency between standards on this point.
No
To specifically address Requirement R1, the Measure should be rewritten to stress that there be familiarity with the protection system schemes applied in its area. Suggest revising the Measure for Requirement R1 to read: Each Transmission Operator, Balancing Authority, and generator Operator shall have evidence that its appropriate personnel were made familiar with protection systems in its area. That can be made easily auditable by having written summaries of the schemes, and have personnel sign offs after reading.
PRC-027-1 in its entirety needs a quality review. Requirement R2 is not written correctly--it does not refer to the entities first. Also, each Requirement has multiple numbered Measures.

The Requirement also states that the functional registration (e.g. GOP) has to demonstrate compliance, not the individual operators. If it is the intent of the Standard that each individual operator of an entity be familiar this should be added. By stating the functional registration as opposed to the individuals, it could be interpreted that as long as any Registered Entity SME is familiar with the purpose and limitations of the protection systems that the entity will be able to demonstrate compliance. Suggested rewording of the Requirement: Each Transmission Operator, Balancing Authority, and Generator Operator responsible for the operation of BES elements shall have its operators be familiar with the purpose and limitations of protection system schemes, either through training or operational experience, applied in its area. There has been a broad variation in how the language of this requirement is applied during audits.
Individual
John Falsey
Invenergy LLC
Agree
Essential Power, LLC
Group
Pepco Holdings Inc. & Affiliates
David Thorne
Yes
No
PHI suggests the definition of Interconnection Element be revised as follows: “Interconnection Element: A BES element that electrically joins facilities a) owned by separate Registered Entities, or b) operated by separate Functional Entities (Distribution Provider, Generation Owner, or Transmission Owner) within the same Registered Entity.” Without this change the existing language could be mis-interpreted as requiring a documented Protection System Coordination Study on each and every internal BES transmission line (transmission line to transmission line coordination) within a Registered Entity’s system, just because the Registered Entity has registered as multiple Functional Entities, and despite the fact that all the lines in question are owned and operated by the same Transmission Owner Functional Entity. The intent of the standard is to address coordination of interconnected elements between separate Registered Entities or between separate functional entities within the same Registered Entity.
Yes
Yes
No
PHI finds that the revised wording in Section R4 does little to address the root problem associated with mandating mutual agreement. PHI suggests Requirement R4 be removed

entirely or extensively re-written to address the concerns outlined below: Requirement R4 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What if agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R4.2 until agreement is reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? This is the problem with mandating that an agreement between two parties be reached. It is further compounded by requiring that an agreement be reached within a set timeframe. It is unreasonable and unfair to hold one party non-compliant due to the failure of another party to reach agreement. Furthermore, in the example provided above, it is a detriment to reliability to delay implementation of the setting change on breaker D just because mutual agreement could not be reached. It is important to ensure that information on new, or modified, Protection Systems are shared between parties, so that each party may assess the impact of the change and ensure their Protection Systems are properly set and coordinated. The emphasis should be on sharing of information (such as relay setting changes) and not the details of performing the "Protection System Study" and all the associated approval schedules. As such, it may be reasonable to have a Reliability Standard to ensure setting information has been exchanged (which was the original intent of the PRC-001-1 standard). But it should be left at that. Mandating mutual agreement with compliance implications, without providing a clear division of responsibilities and assignment of who will be held non-compliant if agreement cannot be reached is unfair to either party.
Yes
Yes
1) The SDT states that "the requirements in the proposed Reliability Standard PRC-027-1 take

into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address the appropriate use of time delays in relays". However, a word search of the 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. The mention of "the appropriate use of time delays in relays" in the 2003 Blackout Report was in the context of the actuating time of relays in response to system overload conditions, and generator protection to voltage and frequency excursions during stressed system conditions. The concern was that relays operated on overload before system operators could react and that some generators tripped (exacerbating the collapse) before other system schemes (UFLS or UVLS) could operate. The solution was not to increase the time delay on Zone 3 relays (which would have been intolerable for fault clearing purposes) but to address the relay loadability issue in PRC-023, to make them immune from operating under heavy load conditions. Similarly the premature tripping of generators on voltage and frequency protection during stressed system conditions (not fault conditions) and coordination with system UFLS and UVLS schemes was discussed in the report. Likewise those issues have now been addressed, or are being addressed, in PRC-006, PRC-010, PRC-022, PRC-019, and PRC-024. Similarly in the recent Southwest Blackout of 2011 the operation of relay schemes during overload conditions was a contributing factor. There was again no evidence of miscoordination of relay schemes during fault conditions. The unexpected operation of relays and SPS's during overload conditions could have been avoided by proper application of existing standards PRC-023 and PRC-014-0. Based on the above, where is the historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions? Reliability Standards should be adopted based on a need to address a known, or probable, reliability issue. As such, although PHI supports the overall desire to ensure that protective systems are "properly coordinated"; PHI sees little value in developing a new Reliability Standard to address something that is routinely practiced and which has not been demonstrated to be a contributor to major system disturbances, or cascading outages. Even the SDT in their rationale for Requirement R1.1 stated that they have no evidence that there is widespread miscoordination between Interconnected Facilities. In lieu of a formal standard to address relay coordination during faults, a simple technical reference document on Protective System Coordination issues may provide equal benefit to the industry. The above comment was also submitted with Draft 1 of the standard. In their response the SDT stated that PRC-027 was being developed in response to FERC Order 693. However, Order 693 only directs NERC to address specific deficiencies in PRC-001 surrounding certain measures and levels of non-compliance relating to the notification and response to the detection of failures in relay protection systems. As such, PHI believes PRC-027 goes well beyond what is was directed by FERC, and the stated purpose of the SAR. PHI urges the SDT to revisit FERC Order 693 and revise this standard as appropriate to address only the stated FERC directives. 2) Based on the arguments presented in the above comments, including the lack of historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions, PHI suggests that NERC conduct a Cost Effective Analysis (CEA) to provide information about cost impacts (e.g.,

implementation and ongoing compliance resource requirements) of this draft standard and its relative effectiveness in preventing widespread blackouts, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of this standard. 3) Requirement R2, Parts 2.1.1 and 2.1.2: Remove the term “interconnecting bus” and replace it with the phrase “point of interconnection between the Entities.” The point of interconnection between the entities is more descriptive in that the interconnection point may not be a physical “bus”, but rather the terminals of a line disconnect switch, terminals of a breaker, specific transmission pole, etc. Even though the point of interconnection is often modeled in a short circuit program as a “bus”, the term “interconnecting bus” has no physical meaning. 4) Requirement R3, Part 3.3: A footnote should be added stating that this requirement does not apply to those temporary setting changes that sometimes are applied during commissioning, maintenance, or investigative testing activities to verify performance of individual protective elements, provided the original settings were returned upon the conclusion of the testing activity. For example, in multifunction relays when testing backup time delayed protective elements (i.e., zone distance or time overcurrent elements) it may be necessary to temporarily disable high speed elements (i.e., pilot or zone 1 elements). In response to this comment the SDT responded that it “believes temporary settings changes are addressed in TOP-002, which incorporated Requirements R5 and R6 from PRC-001-1. Temporary settings applied (or changed) to perform maintenance testing of a relay would not have an effect upon overall coordination of the Protection System, as the relay would likely be taken out of service for such testing.” PHI agrees with this conclusion, however, this standard does not specifically exclude these temporary changes from Part 3.3. Therefore an auditor may conclude that they are in scope for this standard. As such, PHI suggests Part 3.3 be qualified with a footnote to specifically exclude these types of temporary settings. 5) Based on the commentary accompanying Figure 3 in the Guidelines and Technical Basis document it appears that a Protective System Coordination Study (PSCS) is required only if there are protective systems installed on breaker C for the purpose of detecting faults on the BES system. Is there a recommended criteria or generation size below which there is no need for a PSCS, or for a dedicated “fault protection system” at Breaker C to detect faults on the Interconnected BES element? For example, suppose all generation downstream of the Distribution Provider’s system is comprised of solar installations with non-islandizing inverters. In these cases, it would be unusual to install fault detection systems “looking into” the BES system at breaker C even though there is generation installed downstream. The non-islanding inverters with 27/59 and 81O/U protection would isolate the generation upon loss of transmission source when Breakers A and B opened. Similarly, if a small synchronous generator was installed on a downstream distribution feeder with sufficient connected load to “swamp” the generator upon the loss of transmission source, protective relays at the generator location, rather than at Breaker C, would operate to remove the generator upon loss of the transmission system source. In both of these examples, even though there may be overcurrent protection, or fuses, installed on the high side of the transformer for transformer faults, there is no dedicated fault protection system installed at breaker C for the purpose of detecting faults on the transmission system, and as such there would be no need for a PSCS. Is this correct?
Individual

John Bee
Exelon and its Affiliates
No
ComEd believes that the definition should be revised to read “To coordinate time-delayed Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.”
Yes
No
We do not believe that a mandatory PSCS needs to be completed for each interconnected element as stated in Requirement 1. We believe that the design of the Protection System for an interconnected element must first be considered before requiring a PSCS. In cases where high speed protection schemes are redundant, the reliance on time-delayed backup elements would require at least 2 protection system element contingencies. We propose that redundancy should consist of the use of two separate relays and auxiliary relays as per the redundancy test required in the NERC board-approved TPL-001-2 standard. If failure of a single relay or auxiliary relay results in reliance on time delayed back-up protection, we agree that a PSCS should be required, and consequently would agree to the 60 month time frame.
No
This requirement unnecessary burden on the Generation Owner. The fault current seen by Generator Owner’s protective devices depend on the Generation Owners equipment (e.g., the main generator and transformers). So unless those are replaced there should be no requirement on the Generator Owner to review the protection coordination study due to change in fault current at the interconnecting bus which will be due to grid changes. The Transmission Owner will be reviewing those changes and will be coordinating if needed with the Generator Owner. Therefore these requirements should not be applicable to Generation Owner. [Requirement R1 1.1.2 and Requirement R 4 4.1 should also not be applicable to Generator Owner for same reason]. Need to identify which elements of Generator Owner’s protection system are included in this Standard and provide specific criteria for showing coordination with TOs protective devices.
Yes
Yes
Yes
a. For voltage levels at 345Kv and above (EHV), our standard Protection System design utilizes two high-speed pilot schemes, and includes time-delayed backup protection. Due to pilot scheme redundancy, the operation of time-delayed backup elements is an extremely rare event. Our time-delayed backup protection is intended to serve only as a safety net for

extreme events and we do not believe it is cost effective to study time coordination of these elements across our EHV systems. We believe that in cases where high speed protection schemes are redundant, that is designed such that loss of a single relay or auxiliary relay will not result in relying on time-delayed backup relaying to clear faults, the study of back-up element coordination is not necessary and the completion of a PSCS should not be required. b. Additionally, we believe Requirement 1 should state how many protection system failures must be considered for a PSCS. We believe that only one failure is appropriate for the reasons discussed above. c. PRC-001: The proposed Violation Severity Levels for PRC-001-3 R1 are not commensurate with the draft Measure of the Requirement. The current VSL is “High” for failure to be “familiar with the limitations of the protection system schemes applied in its area” and “Severe” for failure to be “familiar with the purpose of protection system schemes applied in its area.” The draft Measure states that the applicable entity “shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel.” The VSLs should be revised to align with the Measure and the “intent” of the Standard and not effectively split out the purpose of Requirement R1 thus requiring specific documentation for a “purpose” and a “limitation”. Exelon suggests the VSLs be revised to the following: Severe: The responsible entity failed to provide evidence that any training evidence exists for basic relaying and any Special Protection Systems within its area. High: The responsible entity failed to provide evidence that all applicable personnel were trained in basic relaying and any Special Protection Systems within its area d. PRC-001: In the Background Section of PRC-027-1 there is a discussion related to PRC-001-1 that was revised as part of Project 2007-03. Specifically, it is stated that in Project 2007-03 SDT retired PRC-001-1 Requirement R2 as because this Requirement addresses data and data requirements that are included in the proposed Reliability Standard TOP-003-2; however, the justification provided in the mapping document associated with Project 2007-03 does not seem to meet the original intent of PRC-001 R2, and does not seem to be a "relocation" of the original requirement (refer to Project 2007-03 Mapping Document Draft 7). PRC-001-1 R2 current revision is as follows: R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible. The Background Section of PRC-027-1 further states that the SPC SDT recommends that Requirement R1 remain in PRC-001-2, until its reliability objective is addressed by either a revision to an existing standard or development of a new Standard. The current revision to PRC-001-2 that removed Requirement R2 was not fully addressed by Project 2007-3 nor voted on by the Ballot Body and therefore Exelon requests that PRC-001-1 R2 be added back in to PRC-001-3 and Project 2007-06, similar to Requirement R1, until its reliability objective by similarly addressed by either a revision or development of a new Standard.
Individual

Nazra Gladu
Manitoba Hydro
Yes
Yes
(1) For clarity, consider re-writing the definition as “A BES Element that electrically joins a Facility owned by: a) a separate Registered Entity, or b) the same Registered Entity that is represented by multiple functional entities (Distribution Provider, Generator Owner, or Transmission Owner).”
Yes
Yes
Yes
Yes
(1) The title of the new PRC-001-3 standard does not seem to be the appropriate title since the standard addresses protection coordination issues, rather than requiring the system operators to be familiar with, and understand the protection system.
Yes
(1) The wordings of the sentence “Examples of Protection Systems where technical justifications may be used include” under heading “Requirement R2 in the “Application Guidelines” are unclear. MH suggests that It read as follows: “Examples of Protection Systems that are not affected by the fault current change include”. Also, under the same section, it’s very confusing as to what relays the following refers to: 4. Reverse power, definite time &/or time overcurrent elements: Designed to coordinate during maximum generation with the transmission system under normal operating conditions and includes the calculation of the percent deviation between the under single contingency conditions regardless of Fault current. Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.). (2) Protection System Coordination Study definition - for clarity, replace the word “that” with the word “which” and insert the word “that” between “demonstrates existing”. Moreover, consider replacing the words “for clearing Faults” with “during Faults” for consistency with the purpose of the Standard. The suggested definition should read “A study which demonstrates that existing or proposed Protection Systems operate in the desired sequence during Faults. This definition should also be changed in the rational for R1 section and Implementation Plan document if it is an accepted change by the SDT. (3) Background - references are made to standards PRC-001, PRC-027, TOP-003, PRC-005, etc. in this section, which in some cases, do

not include the title following the standard number. For consistency, the title should be included, or in the least referred to at the first instance of the standard number in this section. (4) Other Aspects of Coordination of Protection Systems Addressed by Other Projects - replace the period "." at the end of the last paragraph with a colon ":" . Moreover, follow each project number with its title for consistency and clarity. (5) R1.2 - the words "Protection Systems" and 'Currents used" should be written as "Protection System(s)" and "Current(s) used" to maintain consistency with the rest of the paragraph. As a note, consider changing all instances of the words "Protection Systems", "Currents", "owners" and "Interconnected Elements" to "Protection System(s)", "Current(s)", "owner(s)" and "Interconnected Element(s)", to maintain consistency throughout the document. (6) R2.1 - remove the words "Protection System Coordination Study", leaving only the acronym "PSCS", because it has been previously defined in the document. (7) R2.2.1 and M5 - add an "s" or "(s)" to both "Protection System" and "Interconnected Element". (8) M4 - replace "is" with "includes" and "that contains" with "which contain". (9) All measures - for consistency, the phrase "may include, but is not limited to," should be added to each measure. (10) R4.2 - place brackets around the "s" in the following words "modifications" and "issues" for consistency with the rest of the document. Please continue this change throughout the Standard and Technical Guideline document for consistency. (11) 1.2 Evidence Retention - is it necessary to state that "The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit." since this information is already included in the CMEP. (12) R4.2 and M10 - the words "proposed changes and modifications" should be changed to "proposed changes and additions" to mirror the wording in R3.1.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We agree with the revised purpose statement, but reiterate our previous suggestion to add "settings" after protection system (with the "s" removed") to make it clear that it is the coordination of the settings, not the design of protection systems. The SDT's response to our previous comment indicates that: "…settings' are not the only aspect of Protection Systems that can impact the stated purpose." We are unable to come up with any specific examples of what other parameters or actions associated with the Protection System of an Interconnection Element that would require coordination to ensure "Protection System components operate in the desired sequence during Faults". Please elaborate, or revise the purpose statement accordingly.
Yes
Yes

Yes
Yes
No
We do not have any comment on the revised Applicability Section, but continue to express a serious concern with leaving PRC-001 in its present form. As indicated in our previous comment, we do not agree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. This is a training requirement and as such, it should be transferred to the appropriate PER standards. Providing training evidence does not demonstrate that the (operating personnel of) responsible entities are "familiar with" the purpose and limitations of protection system schemes applied in its area. c. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. In response to our previous comment, the SDT indicates that it "…recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database." We do not agree with this recommendation and hold the view that adding the issue to the NERC Issue Data Base is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT should propose a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee's advice/direction for appropriate actions. We do not believe that the SDT or staff has brought this to the Standards Committee's attention. Note that the Standards Committee is responsible for managing the standards development process and as such, can make an informed decision to either request the SDT to expand its scope (via an amended SAR) to address the PRC-001 issue, or to ask staff or the SDT to prepare a separate SAR to address the issue in parallel. Leaving the PRC-001 hanging out there without a recourse is not a satisfactory solution, and may in fact harm reliability. Once again, we urge the SDT to take the initiative to bring this issue to the Standards Committee, with a proposal to amend the SAR or prepare a new SAR, or seek its advice and direction before continuing work on this project.
No
We do not agree with the proposed Measure for the reason as stated under Q6, above.
Group

Duke Energy
Michael Lowman
Yes
Yes
Yes
Duke Energy agrees with the changes made by the SDT to extend the period to 60 months.
Yes
Duke Energy agrees with the changes made by the SDT to extend the period to 60 months.
Yes
Yes
Duke Energy believes that the Facilities section provides sufficient detail and clarity for this standard.
Yes
In the interest of clarity, Duke Energy feels an example of acceptable evidence for measure 3 of PRC-027-1 R2 would be beneficial. In PRC-027-1, Duke Energy identified a potential gap in Figure 4 of the Application Guidelines. Duke Energy believes that without coordination between the DP and TO, it could lead Transmission Planners and System Protection Engineers to disregard the coordination with protection for the tap line between BES and non-BES equipment. Given the proposed definition of the BES, this scenario could potentially pose a risk to the BES without the proper coordination identified in PRC-027-1.
Individual
NICOLE BUCKMAN
ATLANTIC CITY ELECTRIC COMPANY
Agree
Pepco Holdings Inc. and Affiliates
Individual
Don Schmit
Nebraska Public Power District
No
Will there be an expectation that each entity involved with interconnected elements or facilities be pre-identified in any other documentation other than perhaps in each PSCS?

No
In theory I understand the drafting team stating: "The drafting team believes that any conflict resolution should be handled through normal business practices. The old Measure M9 (new Measure M10) has been modified as follows: Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that, prior to implementation of any proposed Protection System(s) changes, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted. The drafting team believes the requestor cannot be held accountable when the other party does not respond". However, I don’t believe that we can predict or project how an audit or enforcement team will apply or misapply this requirement which is cause for concern. There are utilities that will respond but may not respond in a timely manner. This puts all entities unfairly under scrutiny. Perhaps some form of clarification could be added to the application guidelines or another location for example.
My general impression is this standard could be quite a burden to track data for an audit due to the numerous time lines specified that are between entities. My opinion is this will likely result in a difficult to audit standard. This causes concern if we remain in a zero tolerance compliance environment. Consider changing some of the time lines such as 30 and 90 days to 6 months. My general feeling is we should consider other ways to simplify this standard however suggestions I have made have not made it into the draft standard. I recommend more consideration be given to simplification.
Individual
Michael Mayer
Delmarva Power & Light Company
Agree
Ppeco Holdings Inc. and Affiliates
Individual
Mark Yerger
Potomac Electric Power Company
Agree
Pepco Holdings Inc, and Affiliates
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration (“ICLP”)agrees that the updated purpose statement is more appropriate for a BES Reliability Standard. The previous version sought to minimize the faulted

elements – which is a desirable goal in most cases, but may not be the highest priority where multiple interconnected entities are concerned. (Otherwise, the ironic result could be that local service is preserved at the expense of the wider-area system.) The intended Protection System design should predominate, as it will account for any such circumstances.
Yes
The addition of the modifier “BES” to describe the applicable Elements is critical in Ingleside’s view. Without it, CEAs may assume that a Fault study is required for an interconnection at any voltage – an issue highlighted in FERC Order 773 concerning the Definition of the BES.
No
ICLP mostly agrees with rationale for R1 that states “The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame <than 60 months>.” We would take that one step further and argue that far more critical coordination occurs in UVLS, UFLS, SPS, and distance relay schemes – and is already covered in other NERC standards. Fault analyses are comparatively basic, and do not require a re-evaluation unless a material change is made in the local grid. This means that a Generator Owner should be able to make a simple confirmation that nothing has changed since the previous time a Fault study was performed – usually during commissioning or a major reconfiguration. If the TO wants a full Fault evaluation due to a change in the local transmission system, they are free to do so under R1.1.2. Requiring every GO to produce the results of a study that took place years in the past serves no reliability purpose.
No
Although ICLP is not a Transmission Owner, we will be impacted if the TO’s assessment shows a material change in Fault current has occurred in an interconnecting element. We believe our TO has every economic and reliability incentive to contact us if a modification threatens the transmission network. It should be sufficient that the TO show that a coordinated assessment takes place when an appropriate trigger condition occurs.
Yes
Yes
ICLP agrees that consistency between NERC standards is helpful. Since our Protection System maintenance program has been developed specifically to address BES relaying, it is a straight forward process to develop the related Operator training.
No
ICLP believes that the measure should identify that front-line operators are the target audience of the training. As a Generator Operator, we employ engineers, process developers, and operators – and not all of these individuals require basic Protection System training. This ambiguity should be resolved while there is focus on PRC-001.
Individual
Don Jones
Texas Reliability Entity

No
We suggest re-wording the second half of the purpose to say ”such that Protection System components operate in the desired sequence to properly isolate Faults”.
No
We have concerns with this proposed definition surrounding the current state of the proposed BES definition changes especially in light of the multiple possible exclusions that may be allowed. In ERCOT, there are numerous large private-use-networks (PUNs) with generation behind the fence that could possibly be excluded under the new BES definition, based solely on how much power they export to the grid. If the new definition of the BES grants exclusions to these PUNs, then the PUN as well as the Transmission Owner that connects to the PUN would not be subject to the requirements of PRC-027. In our opinion, this presents a risk to the BES in that there could possibly be protection systems associated with the PUN interconnection that might need to be coordinated to properly respond to faults on the BES or within the PUN. These protection systems should require some level of coordination between the entities involved.
Yes
Yes
Yes
Yes
Yes
How many buses away from the Interconnect Element does the PSCS need to cover? Figure 5 of the Application Guidelines indicates that only the next adjacent bus is to be included in the PSCS, which implies that the PSCS only covers up to Zone 2. We understand that PRC-027 does not tell any owner how to perform a PSCS or dictate the specific information that is required for a PSCS. It appears from our understanding that the coordination of protective relays beyond the primary zones that affect the interconnected element are the responsibility of the equipment owner, and that it is up to the owner to determine whether these settings are to be shared with other entities for the interconnected element. Please clarify if this understanding is correct.
Individual
Thomas Foltz
American Electric Power
Yes

Yes
The term “functional entity” is defined in the NERC Glossary of terms and we believe it should be capitalized in this definition.
Yes
Yes
Yes
No
AEP appreciates the drafting team’s efforts to clearly identify the Protection Systems that are applicable to Requirement R1 but is concerned that the combination of Applicable Facilities in Section 4.2 and Requirement R1 may result in burdensome training requirements for the TOP, BA and GOP that do not provide an increase to BES reliability. In particular, the Applicable Facilities includes Protection Systems installed for the Generator Step-Up transformers, Station Service transformers and the Excitation transformers. Nowhere does the standard limit the scope of this applicability to a subset of the Applicable Functional Entities. As a result, an auditor may interpret the standard to require that the TOP and BA be familiar with this level of generator protection for the units connected to their system.
No
The examples of evidence in Measure M1 appear to be overly simplistic compared to the potential scope of R1.
PRC-001-3: R1 – The term “protection system” should be capitalized to match previous versions of this standard. PRC-027-1: Mapping Document – The verbiage in R1.1 of the mapping document does not match the wording in the proposed standard: “Protection System Study” is used instead of “PSCS”. PRC-027-1: Figure 2 – The phrase “generator Protection Systems” is often used by Generation Owner relay engineers to mean the Protection Systems installed for the purpose of detecting faults on and protecting the physical generator, which is clearly outside of the scope of this standard. Therefore, AEP recommends changing the verbiage associated with this figure to remove the phrase “generator Protection Systems” and replace it with a reference to Generator Owner R’s Protection Systems installed for the purpose of detecting faults on the Interconnected Elements. Suggested wording is shown below: Transmission Owner S is to review the Protection System settings associated with Breaker A *and the Interconnected Element* (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, Owner S is to develop proposed Protection System settings associated with Breaker C. Generation Owner R is to review the Protection System settings associated with Breaker C *and the Interconnected Element* (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A. PRC-027-1: R3 & Figure 5 – As written, R3 will place undue burden on each TO, GO and DP to maintain a list of all other entities connected to each

interconnecting bus to which they connect. Furthermore, since the elements are typically owned by the TO, burden will be placed on the TO to respond to requests from other TO's, GO's and DP's as they build their list. R3 and its' associated Figure 5 should be revised such that the responsibility lies with the owner of the Interconnected Element to ensure that relevant information is passed along to each entity who connects to the element when any one entity makes a change.
Group
FirstEnergy
Larry Raczkowski
Yes
Yes
Yes
Yes
Yes
We agree with Part 4.1 of Requirement 4, but we have comments regarding Part 4.2 and have stated below in Question 8.
Yes
Yes
Although we agree with the proposed change, we have reservations of having a standard with only 1 requirement. Please see our comments on Question #8.
In regard to PRC-027-1: We believe that R3, Part 3.1 is covered in R1, Part 1.2 and propose that R4, part 4.2 be reworded to: 4.2. Prior to implementing any proposed change (s) or modifications associated with Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues In regard to PRC-001-3: The title for PRC-001 "System Protection Coordination" and the purpose statement of this standard is no longer pertinent for the only requirement that remains in the standard - entity familiarity with the purpose and limitations of protection system schemes. This remaining requirement is essentially a training obligation and better suited in a PER standard if deemed necessary for reliability. The drafting team also appears to support this view as discussed in the background statements of the PRC-027-1 standard, however, believes this additional work is outside the scope of its project. However, the PRC-001-3 standard should not be left with a title and purpose statement that will cause industry confusion with PRC-027-1. We suggest that this team adjust PRC-001-3 to include the title "System Protection

Awareness" and a purpose statement of "To ensure entity understanding of system protection schemes applied to their assets." FE believes the continuing need for this requirement (PRC-001-3 R1) needs to be carefully considered. NERC standards PRC-023 and PRC-25 address relay loadability limitations. The original blackout report recommendation that drove this requirement appears to now be more thoroughly addressed by those standards. We encourage the NERC Standards Committee to extend the scope of this drafting team's work through a supplemental SAR to address whether or not PRC-001 can be retired.
Individual
Michael Moltane
ITC
Yes
No
The Applicability section 4.2 defines "facilities" as protection systems with the purpose of detecting BES faults on Interconnected Elements. Therefore, in example Figure 4 the DP does not own "facilities" and the transmission line or tap are not an Interconnected Element. The definition of Interconnected Element should reflect this fact and Figure 4 should be corrected. If the intention is that Figure 4 should be an Interconnected Element so that R2 still applies, then clarification that Interconnected Elements does not require Applicability section 4.2 defined facilities is required. ITC Holdings engineers perform coordination at Interconnected Elements between ITC Holdings subsidiaries ITCTransmission and METC, both registered TOs. The definition should exclude applications such as this, where the only outcome is increased administrative burden to be auditable with no reliability benefit to BES.
Yes
Yes
Yes
Yes
ITC Holding is in agreement with the clarification on which protection systems are applicable to requirement 1. Using the same definition as used in PRC-005-2 promotes consistency across the standards within the same category (PRC).
Yes
ITC Holdings is in agreement to add the measure to the standard to be in-line with the language in the RSAW for PRC-001-2.
We vote to reject Draft 3 of PRC-027-1 primarily due to enormous increase in administrative burden with no appreciable gain in system reliability. We agree with SDT there is reliability benefit to performing these tasks. However, as the SDT members stated at presentations to

RFC Protection Subcommittee and to NATF Workshop, utilities are already doing this work. The SDT’s own rationale states “no evidence there is widespread miscoordination of Protection Systems”. Therefore, the only outcome of this standard is that utilities will greatly increase administrative burden to become auditable. Figure 4 exclusion of PSCS on the Interconnected Element is not found in standard. Figure 4 states the line or tap is the Interconnected Element, therefore TO owns “facilities” and must meet R1-R4. Either definition of Interconnected Element must be revised to exclude Figure 4 example, or Figure 4 must be corrected to show TO is still responsible for R1-R4. Example Figures 1-5 create responsibilities on owners to “propose” and “review for coordination” which are not found in the standard. Either these responsibilities should be removed from Figures or the responsibilities should be added to the standard. The last sentence in Figure 5 specifies the TO will provide GO settings to the other TO. This contradicts R3 which states, “Each TO, GO, and DP shall provide to each TO, GO, and DP…” Again, the Figures are creating responsibilities not found in the standard. The purpose of Applicability section 4.2 Facilities is unclear. Each requirement deals with requirements around the Interconnected Elements. If the purpose of section 4.2 is to try and exclude DP relays which do not purposefuly trip for BES faults, this should be more clearly stated. This exclusion should be moved to Interconnected Element definition and section 4.2 rewritten to target Interconnected Elements. Or section 4.2 should be the corrected Interconnected Element definition, and there will be no need for a new definition in this standard. Example Figure 2 creates different responsibilities for GO than Figure 3 does for DP. Why the difference? Essentially they are the same: both have protection systems which trip for faults on Interconnected Element. Again, the Figures are creating responsibilities not found in the standard.
Individual
John Seelke
Public Service Enterprise Group
No
As a Results-Based Standard, “coordinate” should be removed from the Purpose. We suggest that the Purpose should be “To ensure that Protection Systems involving Interconnected Elements operate in the desired sequence during Faults.”
Yes
Yes
No
We agree with that the 60 months is adequate; however, we disagree that a technical justification should be required for relays and schemes that are unaffected by the level of Fault current. See our proposed language changes in 8.a below.
Yes

No
Change section 4.2.1 (capitalized words show changes) as follows: “4.2.1 - Protection Systems that are installed for the purpose of detecting AND ISOLATING Faults on BES Elements (lines, buses, transformers, etc.)”
No
• Requirement R1 requires that “Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.” This is too broad and vague with respect to which TOP, BA and GOP personnel are in the requirement’s scope. Subject to addressing PSEG’s additional comment of “What is meant by “familiar with” in R1?” in the bullet below, PSEG recommends that the requirement at least be revised to: ”Transmission Operator, Balancing Authority, and Generator Operator personnel shall be familiar with the basic purpose and limitations of protection system schemes applied to the BES equipment and Facilities they control.” • M1 should describe methods other than documented training to meet R1 – see the “but not limited to” language. What is an alternative to documented training? What is meant by “familiar with” in R1? Until “familiar with” is better defined, M1 cannot be written.
PSEG has the following additional comments: a. To avoid make-work reporting that is detrimental to BES reliability, PSEG recommends that the Applicability section remove Protection Systems, Interconnected Elements, and Protection System components that do not require coordination. Therefore, we propose that the 4.2.1 be modified with this additional language after “faulted Element”: “, except for the following Protection Systems, Interconnected Elements, and Protection System components that do not require such coordination: • Protection Systems for the Interconnected Element that are owned by the same functional entity of a single Registered Entity. • An Interconnected Element that is protected by overlapping differential relays only (e.g., a Generator Owner’s GSU that is connected to a Transmission Owner’s bus) • Protection System components for which coordination is unaffected solely due to an increase in Fault current, including: • Transformer differential relays • Line current differential schemes • Generator differential or overall differential, bus differential schemes • Step distance protection schemes • Fault detector settings (these settings are guided directly by PRC-023-X) • Breaker failure settings • Directional Comparison Blocking overcurrent schemes b. “Application Guidelines” comments 1. More clarity on what a pre-standard PSCS needs to contain to meet R1.1. Is an e-mail trail from other owners stating that the settings are acceptable? Do calculations need to be shown? 2. Language on p. 21: “The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with Interconnected Elements that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” If there is no problem, why is this standard being proposed? 3. Language on p. 22 that lists examples of Protections Systems where technical justification may be used to exclude the need for a PSCS. Although PSEG has suggested limiting the Applicability in its comments in 8.a, it may be simpler if the standard just listed the Protection Systems that require a PSCS – that would only be overcurrent elements based upon Fault current. If that

scheme is not employed, no PSCS is needed.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Jonathan Meyer
Idaho Power Co.
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Thank you for the opportunity to comment. While we are in favor of this version, we seek clarification on one item. Requirement R2 states that the fault values used in determining the 10% change will be measured at the “interconnecting bus”. While reviewing the examples in the application guideline section, two “interconnecting bus” are labeled in Figure 1, 3, and 4. If the coordination concern is related to the interconnecting element, it would seem reasonable that the “interconnecting bus” for Owner S to place faults on to determine the 10% change is that at Station 1/Transmission owner R, looking at figure 1. This would capture the change in fault current seen by the Owner S Protection System on breaker E. Placing faults on the interconnecting bus behind breaker E if I am owner S does not seem appropriate when considering coordination on the interconnecting element.
Group
Bonneville Power Administration
Morgan Senkal
Yes
No
1. In this new term, the use of “interconnected” implies that the element is connected by another element, which is not what is intended. A more appropriate word would be “interconnecting” as this indicates that this is the element that connects other elements. 2. The definition as written does not make sense because there is typically not an element that electrically joins facilities owned by separate registered entities. Instead, where the point of interconnection between separate registered entities is made, one entity will own the element on one side of the point of interconnection and the other entity will own the element on the other side of the point of interconnection. The change of ownership is made at a point, not through a commonly-owned element. Since all elements are owned by one entity or the other, there is no element that electrically joins the elements owned by the two entities and nothing that meets the definition provided for an Interconnected Element. 3. Part B of the definition does not indicate which element is the Interconnected Element in a system where the same registered entity represents multiple functions. Does this allow the entity to choose which element is considered to be the Interconnected Element? For example, if an entity is both a generator owner and transmission owner they will own all elements from the generator to and including the transmission system, with no change of ownership. There is no clear point where the generator function stops and the transmission function begins. Which element will be considered to be the Interconnected Element and required to comply with this standard?
No
BPA believes that the requirement to provide a protection system study for each interconnected element is onerous, and as a result, any amount of time is too short. While beneficial to periodically perform fault studies and review protection system coordination, the creation of a NERC standard to require reviews for Interconnected Elements on a rigid time

frame is likely to be counterproductive for the following reasons: a. There is nothing unique about the Protection Systems for Interconnected Elements compared to other Protection Systems that warrants this special treatment. If this standard is deemed necessary, the only logical consequence is that similar standards must be created for all protection systems. Trying to coordinate Protection Systems to comply with numerous standards will limit flexibility. Diverting resources from addressing Protection System problems to completing compliance documentation makes the system less reliable, not more. b. This standard provides no quality benefit to the Protection System Coordination process. It only increases the documentation burden, which is just as likely to decrease the quality of the review as it is to improve it. c. There are an enormous number of things that entities do to keep the BES reliable. If NERC wishes to regulate and enforce all of these things, it will come at an enormous cost to consumers of electric power. Cost increases are already being experienced due to the present standards. Since there has been no widespread problem with Protection System coordination between entities, this particular issue should not be the subject of a standard. d. Any specified time frame for a Protection System Coordination review will be too long for some situations and too short for others. The Protection System Engineers within the entities are in the best position to determine an appropriate review interval for each element.
No
Please see comments for Question 3.
No
The requirement does not describe what further actions are required or what time limits apply if the suggested modifications are not acceptable to the originating entity.
No
As described in the Facilities Section, the protection systems for which the requirements are applicable are “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements”. Since most Protection Systems are capable of isolating faulted elements without coordination, nearly all Protection Systems would be exempt from the requirements. While this would be acceptable to us, we don’t think this is what the drafting team intends.
Yes
1. The definition of Protection System Coordination Study is inadequate because it does not address what type of faults must be studied or where on the system the faults need to be applied. 2. R1.1.2 uses the term interconnecting bus. This is not a common term and requires a definition.
Group
PacifiCorp
Ryan Millard
Yes

Yes
Yes
Yes
Yes
Yes
PacifiCorp would like to highlight a recommendation that was made by the drafting team on page 4 of Draft 3 of PRC-027-1 regarding Requirement R1 of PRC-001-2. The drafting team has recommended via the NERC Issues Database that the future standards drafting team tasked with revising PER-005-1 incorporate the reliability objective of PRC-001-2 Requirement R1 into that revised standard. PacifiCorp is concerned with the potential overlap that could result from the failure to retire Requirement R1 in PRC-001-2 concurrent with the effective date of the new version of PER-005. To avoid the risk of entities having to comply with duplicative requirements under two currently-effective standards, the standards drafting team should include language in PRC-001-2 expressly confirming that compliance with the relevant requirement of the revised version of PER-005 will satisfy Requirement R1 of PRC-001-2 until such requirement is retired. In addition, there have been several proposals in the informal development of PER-005-1 that would expand the scope of applicability to include Generator Operators and Support Personnel. If R1 of PRC-001-2 is to be included in the new version of PER-005-1, the requirements of R1 could apply to additional functional entities. As such, any recommendation to move R1 of PRC-001-2 into the new version of PER-005-1 should be part of the PER-005-1 discussions that are currently taking place. At present, they are not. PacifiCorp would like to encourage more collaboration between drafting teams on the development of new draft standards and would like to thank the System Protection Coordination Standard Drafting Team for highlighting this recommendation.
Yes
Individual
Bill Middaugh
Tri-State G &T
Yes
Yes
Yes

Yes
Yes
Yes
No
Tri-State believes that the Requirement R1 and Measure M1 need to refer more directly to the Facilities included in the Applicability section. A couple of options are presented below. Option 1: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of the following protection system schemes applied in its area: • Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.) • Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements. • Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability. • Protection Systems installed as a Special Protection System (SPS) for BES reliability. • Protection Systems for generator Facilities that are part of the BES, including: o Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays. o Protection Systems for generator step-up transformers for generators that are part of the BES. o Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES). o Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays. If Option 1 is chosen, then the Facilities section in the Applicability can be removed. Option 2: M1. For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in the purpose and limitations of the Protection System schemes included in the Facilities section of the Applicability that are used within its area was provided to its applicable personnel.
Tri-State is concerned about the timeframes allowed in Requirement R1, associated with Requirement 3, Part 3.1, especially when the proposed change does not affect the conditions used in the coordination of Protection Systems. The way we read Requirement R3, Part 3.1, a planned relay replacement will have to go through the PSCS process or a technical justification would be required even if it does not affect coordination of other Protection Systems. We would propose that Part 3.1 be changed as follows: 3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnected Element if the proposed change requires a change in the coordination of Protection Systems associated with the Interconnected Element(s); or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).

Individual
Kayleigh Wilkerson
Lincoln Electric System
In consideration that the rationale for Requirement R1 Part 1.1.1 acknowledges that the drafting team has “no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements”, LES recommends further development of the standard be halted until sufficient technical justification can be provided for the standard’s development. As currently drafted, the drafting team would place excessive documentation requirements on registered entities for activities already being performed as industry best practices. In lieu of turning those best practices into compliance requirements, LES suggests the drafting team leverage existing Reliability Standard PRC-001 as a basis for system protection coordination.
Individual
Karen Webb
City of Tallahassee - Electric Utility
Agree
Florida Municipal Power Agency (FMPA)
Group
Salt River Project
Bob Steiger
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Individual
Bill Fowler
City of Tallahassee
Agree
FMPA
Individual
Scott Langston
City of Tallahassee
Agree
FMPA
Group
Dominion
Randi Heise
Yes
1) The SPC standard drafting team created this result-based standard specifically directed toward Interconnected Facility applications by stating in the current draft that “PRC027-1, with the stated pupose ‘to coordinate Protection Systems for Interconnected Elements….’ . Also in Draft#3 the purpose now places emphasis on “desired operating sequence” versus Element isolation. To align with this purpose, as previously suggested, we recommend that the title of this standard reflect the revised purpose and be renamed “Protection System Coordination for Interconnected Elements”.
Yes
1). The word “facilities” included in the proposed definition, “Interconnected Element: A BES Element that electrically joins facilities owned by…” should be capitalized as it is included in NERC’s Glossary of Terms Used in NERC Reliability Standards. 2). Dominion agrees with SERC PCS comment: “As evident by a note in the rational box for R1 (Page 6 of Redline Version) the drafting team recognizes that vertically integrated entities that have the same personnel performing the review of protection systems for the function of the TO and GO could be unnecessarily burdened if the definition were misconstrued to the point of requiring these personnel to display evidence of comparing studies with themselves. To ensure that this intent is retained in the final version of the standard it is suggested that this note or some derivative be placed somewhere in body of the standard such as the definition of Interconnected Element or under the requirements.”
Yes

Yes
Yes
Yes
Yes
Dominion believes the reference to PRC-001-2 is incorrect and should be noted as PRC-001-3 as PRC-001-2, Page 11, cites “Measures and Compliance Elements will be added to a later draft.” Dominion supports the measure accompanying Requirement 1, as included in PRC-001-3. Dominion also notes that the reference to the RSAW for PRC-001-2 is incorrect and should reference the RSAW for PRC-001-1. Dominon was unable to locate a draft of RSAW PRC-001-2 or PRC-001-3 on the Standards Under Development NERC webpage or under any category, on the NERC RSAW page.
1). Under Requirement 2 (Page 8 of Redline Version), studies are referred to as “most recent” and “present” which is confusing and could be considered synonymous. Recommend changing this terminology to replace “most recent” with “previous” study and “present” with “new” study in all places within the standard where they exist. 2). Requirement R3, 3.1 first bullet (Page 10 of Redline Version) is both broad far reaching (new installation, replacement with different types) and specific (modifications to protective relays or protection functions settings, communications CT/PT ratios). 3.1 Clearing targets changes or additions to existing or new Facilities that modify conditions that impact coordination of Protection Systems. Recommend changing bullets to clarify areas of this emphasis to: • Change in Protective Relay Types or Functions • Change in Communication System(s) that interface with Protection System(s) • Change in connected voltage (VT) or current (CT) source ratios • Change to transmission system Element(s) that alters impedance • Change to generator unit (s) that alters impedance • Change to generator step-up transformer (s) that alter in impedance 3). In Application Guidelines – Example Process (Page 30 of Redline Version) the second bullet indicates that a single study can be used whereas in R1 1.1.3 it states that “each” entity shall perform a PSCS. Recommend clarification in this example to reflect Note that is included in Rational for R1 that indicates in cases where a single group performs overall study for the interconnection for both entities. This reference may lead to confusion in the example. 4). Wording is confusing in PRC-027-1 Applicability Section (Page 3 of Redline Version). Suggest combining 4.2 and 4.2.1 into something like “Protection Systems owned by the Functional Entities in 4.1 are applicable if they are installed for the purpose of detecting Faults on Interconnected Elements of the BES and require coordination for isolating those faulted Elements”. 5). There are numerous locations in the standard that note that “Protection System Coordination Studies are typically performed assuming maximum generation and all Facilities in service.” Given the complexities of system configurations, it is not always the case that this scenario (Max Gen and All Facilities In) will be the best case under which to verify proper coordination. Recommend removing this note and require entities to determine the best scenario under which to evaluate coordination.

The presence of this note may create unintended bias. 6). Dominion agrees with SERC PCS comment: “Please change Figures 3 and 4 in the Applications Guidelines section so that “Interconnected Element” is adjacent or points to the line between Breaker C and the point of connection (tap point) on the line between Breakers A and B. It clarifies these examples by having the Figures align with your wording. (The Figures presently imply that the line between Breakers A and B is the “Interconnected Element”.)
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No
In our area, there do not appear to be any issues with lack of protection system coordination and I am unsure if there is really a need for this standard. Their appear to be adequate protection systems standards noted in the "Other Aspects of Coordination of Protection Systems Addressed by Other Projects" section.
No
It is difficult to support the current definition that relies on the BES Element language from the BES definition process that has not been finalized. In our case, there are elements that would not be in scope for Interconnected Element consideration, but if there is no finalization of the BES definition and this standard moves ahead, the heart of this definition would be in flux. More specificity in what equipment we are really talking about here might be helpful in the absense of a settled definition of a BES element.
Yes
Yes
No
Although well-intended, this seems like a difficult thing to document for audit if there are legitimate back and forth over a long period of time.
No
Do not believe that a DP-only entity would typically have Interconnected Elements that would necessitate inclusion, when the purpose is to protect the TO equipment.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
No

Change "in the desired sequence" to "in an acceptable sequence". This better reflects the compromises that may be required by the different entities owning protection systems on an Interconnected Element.
Yes
No
Requirement 3.3 needs to be revised to allow an entity the flexibility to make emergency changes to protection systems or settings that are necessary to correct a reliability problem. The current draft allows such changes only when a failure occurs.
Yes
No
R4 needs revision to better accomodate the entire range of diversities in TO-GO interconnections, especially when agreement cannot be reached between entities, or when agreement cannot be reached in a timeframe required to make critical changes during generating unit outages. R4 also neeeds to include flexibility when the GO is not a vertically integrated utility, and does not have in-house protection engineering resources to respond in the required timeframe. It is unjust to put compliance risk on an entity due to the failure of another entity to reach agreement on settings. In some cases the best that can be expected is for two parties to exchange protection system information and live with a compromise in coordination that allows both to best protect their assets. This may be especially true when generating assets are at stake, and insurance considerations require sensitive protection that may not allow complete coordination.
Individual
Richard Vine
California ISO
See associated SRC Comments
See associated SRC Comments
See associated SRC Comments
See associated SRC Comments
See associated SRC Comments
See associated SRC Comments
See associated SRC Comments
The ISO feels that a requirement should be added for the TO, GO or DP to notify their TOP and PC when a new or revised Remedial Action Scheme or Special Protection System is implemented.

Group
PJM Interconnection
Stephanie Monzon
Yes
Yes
Yes
Yes
PJM supports both standards as drafted. Specific to PRC-001-3 R1, PJM urges the SDT to replace the term ‘familiar’ with language less subjective. There may be a number of interpretations for this term that will result in compliance issues for applicable entities. Suggested revised wording should include language that has a direct tie to the Measure. PJM recommends the following revised requirement for the applicable entities, ‘knowledge of the purpose of and limitations of protection system schemes shall be based on the training programs provided.’
Individual
David Jendras
Ameren
Yes
(1) Ameren supports the SERC Protection & Control Subcommittee comments and hereby includes them by reference rather than repeating them all.
Yes
(1) The word “facilities” should be capitalized, since it is included in the NERC Glossary: “Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)” and “Element - Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.”
Yes
Yes

(1) The "maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus" could either be the total Fault current at that bus, or the Fault current flowing through the Interconnected Element. Our reading of R2, Part 2.2 "used in the most recent PSCS" is that it depends on what the entity used in their study.
Yes
Yes
Yes
(1) The measure was provided for PRC-001-3, not PRC-001-2.
(1) In Application Guidelines for R1, please add “A Protection System Coordination Study includes, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed.” We request adding it just after the definition of a PSCS. This will more clearly align the Application Guidance with R1.2. (2) Under Requirement 2, studies are referred to as “most recent” and “present” which is confusing and could be considered synonymous. We ask the SDT to change this terminology to replace “most recent” with “previous” study and “present” with “new” study in all places within the standard where they exist. (3) Requirement R3, 3.1 first bullet is both broad (new installation, replacement with different types) and specific (modifications to protective relays or protection functions settings, communications, CT/PT ratios). The 3.1 text itself clearly targets changes or additions to existing or new Facilities that modify conditions that impact coordination of Protection Systems. We request the SDT to replace the existing bullet points to clarify areas of this emphasis to these bullet points: “• Change in Protective Relay Types or Functions • Change in Communication System(s) that interface with Protection System(s) • Change in connected voltage (VT) or current (CT) source ratios • Change to transmission system Element(s) that alters impedance • Change to generator unit (s) that alters impedance, or • Change to generator step-up transformer (s) that alter in impedance” (4) We request the SDT to clarify 4.2 by combining 4.2.1 into it, thus removing the separate 4.2.1. Please reword as follows: “These requirements contained herein are applicable to each 4.1 Functional Entity that owns Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.”
Group
Bureau of Reclamation
Erika Doot
Yes
Reclamation appreciates and agrees with the drafting team’s clarification of the Purpose section. Reclamation agrees with the drafting team that it is more important for Protection System components to “operate in the desired sequence during Faults” than to have “the least number of power system Elements” isolated to clear Faults as previously stated in Draft 2 of the Purpose section.

No
Reclamation appreciates the drafting team's clarification of the definition of Interconnected Element to specify that Interconnected Elements must be "BES Elements." However, Reclamation believes that the addition of part b) of the definition is problematic. Reclamation believes that "Interconnected Elements" covered by the standard should only join facilities owned by separate Registered Entities as specified in part a) of the definition. Reclamation is not clear on how an entity would document internal coordination of Protection System Coordination Studies for the TO and GO arms of the same entity. Reclamation notes that the examples provided by the drafting team in the Application Guideline Diagrams appear to describe only Interconnected Elements at the point of demarcation between separate registered entities. At some Reclamation facilities, the same staff members coordinate TO and GO relay settings, so it is not clear how the studies and concurrence required under R1-R4 would be accomplished. Reclamation believes that PRC-023, PRC-025, and other standards will ensure that TO and GO relay settings are appropriate, and that PRC-027 should only address relay setting coordination where facilities join separate Registered Entities. In addition, the Background section of the standard explains that one purpose of the standard is to address the August 14, 2003 blackout report recommendation on the need to "address 'the appropriate use of time delays in relays,' by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination. Consistent with this rationale, Reclamation recommends that the drafting team modify the definition of Interconnected Element to read, "A BES Element that electrically joins facilities owned by separate Registered Entities." Finally, Reclamation notes that the definition of Elements in the NERC Glossary is, "Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components." By incorporating the term Element, PRC-027-1 perpetuates the ambiguous definition of Elements by including the term "such as," which creates an open-ended list of possible Elements. Reclamation believes it would be helpful for entities to have a better defined list of possible "Interconnected Elements" so that Entities can ensure compliance.
Yes
Yes
No
Reclamation agrees with this comment but suggests rephrasing R4 to encourage collaboration among registered entities. Reclamation suggests that R4.1 should read "Within 90 calendar days after receipt or according to an agreed upon schedule, review the summary results of a PSCS (per Requirement R1, R1.2) and respond to the other owner(s) by accepting the results or suggesting modifications to resolve any identified coordination." Reclamation does not believe that entities should submit formal rejections of PSCSs merely to satisfy the standard. Reclamation suggests that the phrasing above would better encourage collaborative relay setting coordination.

No
Reclamation requests that the drafting team clarify which Protection Systems “require coordination” for isolating faulted Elements, or remove the phrase “that require coordination” from the definition of Facilities.
Yes
Reclamation thanks the drafting team for assisting Registered Entities with the transition from PRC 001 to PRC-027 by incorporating the RSAW language to ensure continuity of compliance.
1. Reclamation requests that the drafting team clarify what "acceptable evidence" it envisions for PSCSs. For an example, is a PSCS acceptable if the document contains (a) Date of study, (b) Deviation of short-circuit currents, (c) System change, (d) all recipients, etc. We appreciate if you can include an example form/document as acceptable evidence. Reclamation would appreciate if the drafting team added a sample PSCS template that would be considered acceptable evidence. 2. In order to avoid similar vagueness of coordination issues that were problematic under PRC-001, Reclamation would appreciate if the drafting team clarifies what a PSCS should contain (e.g. which relay element(s) is required to coordinate with, how to show it as the evidence, etc.)The PRC-025 documents may provide helpful examples. 3. Regarding R1 & M1, if a PSCS shows no impact on the existing coordination (no setting changes are required), would an entity still have to send neighboring utility(s) the entire PSCS supporting study or would a brief statement of the study results suffice? Reclamation requests that the drafting team clarify the acceptable evidence. 4. Reclamation suggests that R2 should be revised to read, “For each interconnected element on its System, the TO shall, once every 60 calendar moths, technically justify if a fault current has changed more than 10% but does not affect to the Power System coordination, or …” rather than "techincally justify why Fault current does not affect the Protection System coordination." 5. Reclamation requests clarification of the items requiring coordination listed in R3.1. Reclamation believes that the current list implies that any changes in relay equipment or settings would require coordination.
Group
DTE Electric
Kathi Black
No
Comments: Since the main purpose of this standard is to assure coordination of BES Interconnected Elements, there should be a provision included to require TOs to provide system fault data to DPs and GOs on a continuous basis so that coordination is performed on BES as well as non-BES elements using the latest data. If complete system fault study files are provided regularly (bi-annually?), projects can be completed using the latest data and not subject to re-evaluation when an update is provided by the TO every 60 months.
Yes
None
Yes
None

No
Comments: Since the main purpose of this standard is to assure coordination of BES Interconnected Elements, there should be a provision included to require TOs to provide system fault data to DPs and GOs on a continuous basis so that coordination is performed on BES as well as non-BES elements using accurate data. If complete system fault study files are provided regularly (bi-annually?), projects can be completed using the latest data and not subject to re-evaluation when an update is provided by the TO every 60 months. It is critical that fault study data file compatibility exists between the short circuit programs of the different entities.
Yes
None
Yes
None
Yes
None
Comments: Different entities that are highly integrated electrically should be using the same short circuit data. If fault data files could be exchanged regularly (bi-annually?) using compatible file formats, short circuit databases wouldn't drift apart (as would occur after five years) and coordination studies could be performed with more confidence. Many settings could require re-visiting when the once every five year fault current update is received. It should be noted that while the emphasis is on BES Interconnected Elements, many other non-BES Interconnected Elements, such as radial distribution transformers, could be affected resulting in a negative impact on the BES.
Group
Southern Company
Pamela Hunter
No
Suggest that "the desired sequence" be replaced with "an acceptable sequence" to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in an acceptable sequence during Faults. e.g. the GO and TO may not have the same desires.
Yes
Yes
Yes
Yes

Yes
No
While we agree with the changes made to the applicability section and the measurement section, we believe that it is not necessary to separate "limitations" from "purpose" in the VSL, and recommend that a single Severe VSL be used to cover all of R1 by using the requirement R1 verbiage "…familiar with the purpose and limitations of …". Will compliance be evidenced by training records for individuals, the content of the training, or both? How might the "familiar with limitations" and "familiar with purpose" be separately evaluated in an audit?
(a) The purpose statement for PRC-001-3 needs to be changed to match the content of the sole requirement. If this one requirement is to be absorbed by PER-005, consider keeping the purpose and moving the content of PRC-027 back into PRC-001. (b) Please retain one measure per requirement so that the Measurement numbers match the base requirement number. The evidence required for each sub part of each base requirement can be described in the same section as the other sub parts. (c) There is no equation found in R2.2. (d) In R3.3, it is not clear when the 30 days starts - is it the 30 days following the change(s)? (e) R3.3 should be limited to Protection Systems associated with Interconnected Elements. (f) 4.2 can hold an entity hostage if the other Interconnected Element owner does not/will not accept/reject the changes.
Individual
RoLynda
Shumpert
Agree
SERC PCS
Group
North American Generator Forum Standards Review Team
Patrick Brown
No
The expression "the desired sequence" should be replaced with "an acceptable sequence," since the GO and TO may not have the same desires.
Yes
Yes
Yes
No
R4.2 can hold an entity hostage (and possibly non-compliant) if the other Interconnected Element owner does not/will not accept the proposed changes. This requirement is extremely objectionable for entities in deregulated markets, since the “firewall” separating the regulated

and deregulated sides of the business would ordinarily prevent the GO from seeing TO critical infrastructure information. R4.1 speaks of sharing only, “summary results,” but the Application Guidelines calls on p.24 for transmittal of, “power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings.” R4.2 also raises concerns for the situation in which a TO connects to GOs within the same corporate umbrella as well as to GOs that are part of completely separate corporate entities. The TO is legally required to treat all GOs equally, and we would certainly expect this to continue to be the case if PRC-027 is enacted, but suspicions could arise whenever expansion plans of a TO are impeded or overtly vetoed via PRC-027 “reject” decisions by an other-corporate-entity GO and vice-versa. Proposed changes to Interconnection Service Agreements are handled under market rules, and NERC standards should not contain features that might create opportunity for infringing-on or bypassing these rules.
Did you mean PRC-001-3? If so, the response is, “Yes.” We believe however that PRC-001 should be left as-is and PRC-027 should be made an exclusively TO-applicable standard, as explained elsewhere in these comments.
No
a. Did you mean PRC-001-3? b. It is not necessary to separate "limitations" from "purpose" in the VSL, and recommend that a single Severe VSL be used to cover all of R1 by using the requirement R1 verbiage "…familiar with the purpose and limitations of …" PRC-001 moreover should remain as is, with PRC-027 being applicable to GOs under only very limited circumstances, as stated above. c. The word “area” in R1 of PRC-001-3 needs to be defined for compliance to be measured and enforced. The area for GOs should be restricted to the plants they own, if PRC-001 is modified (see other comments).
a. R3.3 should be limited to Protection Systems associated with Interconnected Elements. b. There is no change needed to the present system: -The TOP is provided with detailed information of GO equipment via PRC-001 and MOD-010, and the TO (being informed of these inputs by the TOP) is then at liberty to modify their Protection Systems if needed. - We periodically request data for available fault current at the interconnect point from the TO, for use in our aux system short circuit studies Changes in the T&D system otherwise don’t matter to GOs. We do not modify our Protection Systems in response to changes to the Fault current at an interconnecting bus, we just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Everything involving sequencing the tripping of multiple Elements is in the TO’s system. The most that could reasonably be asked of independent GOs is to have a valid Interconnection Service Agreement (ISA), since a coordination study is performed by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so detailed evidence could not be asked of the GO. The SDT states on p.21 of PRC-027 that “The drafting team has no evidence there is widespread mis-coordination between Owners of Facilities,” and, “records collected for reliability standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” This appears to indicate that the present system is working and therefore there is no need to go back to existing unit’s coordination studies to make sure they crossed all of the T’s and dotted all of the I’s according to a standard that retroactively

applies requirements that were not in existence at the time of the original coordination studies. c. The purpose statement for PRC-001-3 needs to be changed to match the content of the sole requirement. If this one requirement is to be absorbed by PER-005, consider keeping the purpose and moving the content of PRC-027 back into PRC-001. Please retain one measure per requirement so that the Measurement numbers match the base requirement number. The evidence required for each sub part of each base requirement can be described in the same section as the other sub parts.
Individual
Brett Holland
Kansas City Power and Light
Yes
Yes
Yes, as long as the standard only requires documentation in cases where there are neighboring owners that need to agree on protection and control. As an owner of multiple functional entities, we believe that the BES would not benefit by an intra-utility documentation process, not when the required due diligence is already performed within our System Protection Engineering group. Our System Protection Engineering group is already responsible for the coordination of all protection, whether generation, transmission, or distribution.
Yes
The modification to a longer time frame is acceptable. However, we do not agree that there is adequate justification for requiring a fault current review every five years. Relay settings that are valid today will remain valid until changes are made at our end of an interconnected element or when another Registered Entity notifies us of change. A technical justification that is valid today will remain valid until changes are made to the BES within our system or a neighboring owner's system.
Yes
Yes
Yes
1) The definition of Protection System Coordination Study should be changed to "A study that documents the intended sequence of operation for clearing faults of an existing or proposed Protection System." The word "demonstrates" implies that live testing should be conducted to prove the sequence of operation. 2) In the Rationale for R1, Part 1.1.2, the following portion should be deleted, "e.g. when a line is protected by dual current differential systems with no backup elements set that are dependent upon fault current." The deleted portion should be

replaced with “Refer to the Application Guidelines for Requirement R2 for examples of protection systems where technical justifications may be used.” 3) Requirement R2 specifies a 10% change in fault current as the trigger for a review of the Protection Coordination. We believe that the only time that a Protection Coordination Study should be required is if the fault current increases by more than 10%. Fault studies are typically conducted with all generation on, but we know that this is not the normal system configuration year round and the system could be operating below the 10% fault current threshold. Unit outages are anticipated and fault detecting elements are set to operate even during outage conditions. Elements that coordinate at higher fault current values will coordinate at reduced values. Our suggested change would not preclude a Registered Entity from initiating a Protection Coordination Study upon the reduction of fault current by 10%.
Group
Iberdrola USA
John Allen
Agree
NPCC
Group
MRO NERC Standards Review Forum
Joseph DePoorter
Yes
No
NSRF’s concern with the proposed definition is related to part B of the definition, on how to prove compliance in case of a vertically- integrated Registered Entity where one department is responsible for performing PSCS and the same Registered Entity is performing multiple functions. Recommend that the measures be updated for both part A and part B or clarity within the RSAW.
No
As currently written, each TO, GO and DP are required to perform a PSCS. This will lead to multiple efforts by each entity. Recommend that GO and DP be removed from this Requirement. Since the TO has access to the hierarchy of systems (Interconnected Elements) they are positioned to request current protection system settings from the GO and DP and then perform a PSCS. They can then request adjustments by the GO and DP in order to assure a more secure system.
Yes
Yes
Yes

Yes
PRC-027-1: The proposed standard contains 30-day and 90-day timing requirements in addition to the 60-month requirement. Please consider revising the 30 calendar day's provision in requirements R2.2.1, R3.2 and R3.3 to 90 calendar days to avoid possible confusion between different timing requirements in the standard. We do not see a basis on why there needs to be different dates. If all dates were 90 days, it would provide consistancy for entities to follow. In consideration that the rationale for Requirement R1 Part 1.1.1 acknowledges that the drafting team has "no evidence there is widespread mis-coordination of Protection Systems associated with Interconnected Elements", LES recommends further development of the standard be halted until sufficient technical justification can be provided for the standard's development. As currently drafted, the drafting team would place excessive documentation requirements on registered entities for activities already being performed as industry best practices. In lieu of turning those best practices into compliance requirements, NSRF suggests the drafting team leverage existing Reliability Standard PRC-001 as a basis for system protection coordination. PRC-001-3: Please consider revising the Purpose of PRC-001-3 to reflect the one remaining requirement. With the updated measure there is an inconsistency between the Purpose, the Requirement, and the Measure. We suggest revising the Purpose to PRC-001, the following: To ensure familiarity with the purpose and limitations of protection systems operated by the entity. Suggest revising Requirement R1 to: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall train its applicable personnel to be familiar with the purpose and limitations of protection systems operated by the entity. The above rewrite now provides a clear and understandable (plus it adds to system reliability) Standard for the applicable entities to follow. The Standard sets a minimum level of training concerning protection systems that entities operate. An entity can always provide training on non-operated protection systems, whereby the entity has determined (based on risk to their system) the scope of training outside the proposed rewrite.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes
No
AECI remains unclear as to the intent and effect of PRC-027-1's definition for "Interconnected Element" with respect to clause-b, "the same Registered Entity…" clause. As written, this clause potentially captures all internal BES Elements that electrically joins any internal facilities owned within a Registered Entity that represents multiple functional entity responsibilities. Does clause-b intend to scope additional BES Elements: 1) that electrically join facilities between legally distinct entities within the same Registered Entity (including a JRO) that

represents multiple functional entity responsibilities (Distribution Provider, Generation Owner, or Transmission Owner), or 2) that (even within a JRO) electrically join only functionally distinct facilities within the same Registered Entity that represents different functional entity responsibilities such that internally included Elements join: DP-GO, DP-TO, GO-TO, while internally Excluded Elements join: DP-DP, GO-GO, TO-TO?
Yes
Yes
Yes
Yes
Yes
AECI seeks additional clarify of the SDT's intent as to how base PSCS requirements are to be applied within a JRO, and if R1-R2 serves legitimate reliability function, where R1.1.3, & R3-R4 do not apply to intra-JRO interconnected elements because JROs already internally do these; a JRO would still perform R1.1.3 & R3-R4 for interconnected elements with other registered entities; also clarify that R1 would only require one “master” PSCS for the JRO as opposed to multiple studies for each functional entity within the same JRO.
Group
SPP Standards REview Group
Robert Rhodes
Yes
No
Our concern with the way the definition is worded relates to how to prove compliance between separate entities as well as entities within a vertically integrated utility. How would a Registered Entity actually show that the proper coordination took place? In some instances it appears that evidence would have to be provided for coordination within the same department of an entity. On the other hand, if separate entities are involved, just what evidence would be required to show adequate coordination? Does this need to be formal documentation indicating all the owners of the interconnecting facility?
Yes
Yes

No
The way the requirement is currently worded, the sending entity could conceivably be found non-compliant if an entity receiving the results does not respond within 90 days. We would suggest incorporating language to clarify that the receiving entity has the obligation to respond within 90 days. This could be accomplished by inserting 'each recipient of the results shall' in the requirement. The requirement would then read "Within 90 calendar days after receipt, or according to an agreed upon schedule, each recipient of the results shall review the summary results of a PSCS…"
Yes
Yes
While we concur with the proposed measure, there does appear to be a mismatch between the requirement and the measure. See our comment in Question 8 below to address this issue.
PRC-027-1 As drafted the standard contains 30-day and 90-day timing requirements in addition to the 60-month requirement. Would the drafting team consider making the 30-day and 90-day requirements the same, for example 90 days? This would make staying abreast of timing issues much simpler. Figure 4, Application Guidelines The Note at the bottom of Figure 4 is misleading in that it states that no PSCS is required under this scenario. However, Transmission Owner R is required to have a PSCS for the Interconnected Element between Breakers A and B. The Distribution Provider S is not required to have a PSCS for Breaker C. PRC-001-3 Purpose The existing purpose does not fit the single requirement that is left in the standard. We would suggest changing the purpose to the following: To ensure familiarity with system protection schemes utilized within an operating entity's area. Requirement R1 Similarly, the requirement does not match the proposed measure. We suggest modifying the requirement to: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall train its applicable personnel to be familiar with the purpose and limitations of protection system schemes applied in its area.
Group
ATCO Electric
Rowell Crisostomo
No
- R1 referring to other requirements with different timelines is very confusing to understand and execute. - R1 (and PRC-027-1 draft 3 in general) also has too many timelines: 90 calendar days, 60 calendar months, 12 calendar months, "agreed upon timeframe", etc. - Requirement R1.1.2 – A 10% change in fault current isn't much in some areas of ATCO Electric's system, perhaps as little as a few hundred amps. This could lead to a burdensome requirement to frequently review the same areas of our system. Ten percent seems fairly restrictive when we typically use safety margins of 40% to 50% in selecting instantaneous overcurrent settings.

No
- R2 referring to other requirements with different timelines is very confusing to understand and execute. - R2 (and PRC-027-1 draft 3 in general) also has too many timelines: 90 calendar days, 60 calendar months, 12 calendar months, "agreed upon timeframe", etc.
Can the drafting team draw all timelines in 4 requirements together in a chart to see how these timelines fit together for an entity?
Individual
Jack Stamper
Clark Public Utilities
Yes
No
There still is some concern regarding coordination within a Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner). This type of Registered Entity is one organization and the standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one entity. The comments below provide specifics of these concerns. In order to address these concerns it is suggested that the words “separate” and “same” in this definition be capitalized for reference purposes. The definition should be modified as follows: Interconnected Element: A BES Element that electrically joins facilities owned by: a) Separate Registered Entities, or b) the Same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).
No
The revised time frame of 60 months is agreeable, however, requirement 1.2 should not be applicable to any Interconnection Element owners that are part of the “same Registered Entity that represents multiple functional entity responsibilities.” Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the organization that developed the Protection System Coordination Study to provide a copy to “other owners”. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. Since the definition of Interconnection Elements incorporates the concept of “Separate Registered Entities and “Same Registered Entities” it is suggested that the wording be modified to incorporate theses terms as follows: R1.2 Within 90 calendar days after the completion of each PSCS, provide to the other Separate Registered Entities that are owner(s) of the Protection System(s) associated with the

Interconnected Element(s), a summary of the results of each PSCS performed pursuant to Requirement R1, Part 1.1, (including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed).
No
The revised time frame of 60 months is agreeable, however, requirement 2.2.1 should not be applicable to any Interconnection Element owners that are part of the “same Registered Entity that represents multiple functional entity responsibilities.” Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the organization that developed the updated Fault current study to provide the updated Fault current values (Iscs) to “each owner” of the Protection System associated with the Interconnected Element. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. Since the definition of Interconnection Elements incorporates the concept of “Separate Registered Entities and “Same Registered Entities” it is suggested that the wording be modified to incorporate theses terms as follows: R2.2.1 Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (Iscs) to each Separate Registered Entity that is an owner of the Protection System associated with the Interconnected Element.
No
The response options are agreeable, however, requirement 4 (and any sub-requirements) should not be applicable to any Interconnection Element owners that are part of the “same Registered Entity that represents multiple functional entity responsibilities.” Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the same organization that developed the Protection System Coordination Study to provide a document accepting it or rejecting it. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. Since the definition of Interconnection Elements incorporates the concept of “Separate Registered Entities and “Same Registered Entities” it is suggested that the wording be modified to incorporate theses terms as follows: R4. Each Transmission Owner, Generator Owner, and Distribution Provider that is a Separate Registered Entity and each Same Registered Entity (on behalf of its multiple functional entity responsibilities) shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] 4.1. Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a PSCS (per Requirement R1, Part 1.2) and respond to the Registered Entity providing the PSCS: • Accepting the results, or • Rejecting the results and suggesting modifications to resolve any identified coordination issues. 4.2. Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other Separate Registered Entities that are owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the

resolution of any identified coordination issues.
Yes
Yes
Requirement 3 (and any sub-requirements) should not be applicable to any Interconnection Element owners that are part of the “same Registered Entity that represents multiple functional entity responsibilities.” Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the same functionally registered entity that developed the details for proposed changes to provide a documentation of those details to all other functionally registered entities. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. Since the definition of Interconnection Elements incorporates the concept of “Separate Registered Entities and “Same Registered Entities” it is suggested that the wording be modified to incorporate theses terms as follows: R3. Each Separate Registered Entity and each Same Registered Entity shall provide to each other Separate Registered Entity connected to the same Interconnected Element: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning] 3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnected Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s). • New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios • Changes to a transmission system Element that alter any sequence or mutual coupling impedance • Changes to generator unit(s) that result in a change in impedance • Changes to the generator step-up transformer(s) that result in a change in impedance 3.2. Requested information related to the coordination of Protection Systems associated with an Interconnected Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule. 3.3. Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.
Group
Cooper Compliance Corp
Mary Jo Cooper
Yes

We feel this is a good compromise to making the applicability the Transmission Planner. In our earlier comments we noted that we feel the drafting team should identify the Transmission Planner to be the entity who performs the studies as this is the function identified for the TP. The drafting team responded by stating they changed the Purpose.
Yes
We would like confirmation that this proposed Standard only requires a study for elements that have been determined to be BES elements. For example, a study would not be required on Elements that connect a radial line serving only load because by definition of BES, there are no BES elements to study.
Yes
Yes
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
Comments: The expression "the desired sequence" should be replaced with "an acceptable sequence," since the GO and TO may not have the same desires.
No
Section b) of the definition should be deleted. An “interconnected element” subject to these requirements should not include elements owned/operated by the same registered entity. To minimize the impact of equipment outages under fault conditions, coordination studies are routinely performed by vertically integrated utilities that own and operate facilities that extend from generation plants to distribution pole top transformers. The requirements appear to be intended to insure this same level of coordination is achieved between disparate owner/operators of upstream and downstream facilities. Moreover, as used throughout industry the term interconnected generally refers to electrically contiguous facilities belonging to different operators. After eliminating part b) of the definition, PRC-027 requirements would still apply to vertically integrated registered entities at each point of interconnection with facilities owned/operated by unaffiliated and separately registered entities performing as, e.g., DPs, GO/GOPs, neighboring TOs as appropriate.
No
There is no basis for performing studies every 60-months. Such studies should be performed when necessary based on predetermined criteria set forth in the standard. There is no

evidence of wide spread miscoordination of Protection Systems associated with Interconnected Elements. In fact, none of the recent blackouts resulted from miscoordination of protective settings.
No
See response to question 3 above.
No
90-days is not in all cases the appropriate time period to review such results. The terms and conditions for generator interconnections are regulated by FERC or state PUCs. The proposed reliability standard should clearly state that responsible entities are not obligated to take any actions that are inconsistent with the rights of the parties under any interconnection or similar agreements. Such agreements typically address the procedures for making modifications to a party's facilities that may affect the other party and the required notice and approval rights. The standard should not seek to impose any requirements that are inconsistent with these contractual rights. R4.1 speaks of sharing only, "summary results," but the Application Guidelines on p.24 lists as examples "power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings." We recommend that the above list be preceded with the words "summaries of."
No
Did you mean PRC-001-3? If so, the response is, "Yes."
No
a. Did you mean PRC-001-3? b. The word "area" in R1 of PRC-001-3 needs to be defined for compliance to be measured and enforced. The area for GOs should be restricted to the plants they own, if PRC-001 is modified (see other comments).
a. PRC-027-1, R3.3 should be limited to Protection Systems associated with Interconnected Elements b. There is no clear indication of need to change the present system. The SDT states on p.21 of PRC-027 that "[t]he drafting team has no evidence there is widespread miscoordination between Owners of Facilities," and "records collected for reliability standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations." The purpose statement for PRC-001-3 needs to be changed to match the content of the sole requirement. If this one requirement is to be absorbed by PER-005, consider keeping the purpose and moving the content of PRC-027 back into PRC-001. c. Please retain one measure per requirement so that the Measurement numbers in PRC-027-1 match the base requirement number. The evidence required for each sub part of each base requirement can be described in the same section as the other sub parts.
Group
Tennessee Valley Authority
Dennis Chastain
Agree
SERC Protection & Control Subcommittee(PCS)
Individual

Joe Tarantino
SMUD
No
SMUD believes the purpose of this standard should state: “To coordinate Protection Systems for Interconnected Connection to help ensure Protection System components operate as expected for off-nominal conditions. We believe that the coordination is an effort to avoid misoperations a condition that may occur if the purpose statement is not met. We further believe that the coordination should not only cover a Fault condition but other intended operation that the protections scheme would cover, i.e. power swing, out of step tripping/blocking, etc.
No
SMUD believes the Interconnected Element should be defined as those BES elements that electrically join two or more facilities. SMUD disagrees with differentiating ownership as this delineates those requirements based upon ownership causing confusion and an administrative burden for those entities that solely own and coordinate protection components to demonstrate compliance for internal notifications.
No
The revised time frame of 60 months is agreeable, however, requirement 1.2 should not be applicable to any Interconnection Element owners that are one of the same Registered Entity that represents multiple functional entity responsibilities. There are several Registered Entities that have only one person or department within a utility that is responsible for protection system coordination for all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the organization that developed the Protection System Coordination Study to provide a copy to “other owners”. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner.
No
Please see our comments in Question #3; The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner.
Yes
Yes
The timing provided in R3.1 is contains no specification that correlate to the timing requirements of the other R3 subrequirements .
Group
SERC Protection and Controls Subcommittee

David Greene
Yes
Yes
As evident by a note in the rational box for R1 (pg. 6) the drafting team recognizes that vertically integrated entities that have the same personnel performing the review of protection systems for the function of the TO and GO could be unnecessarily burdened if the definition were misconstrued to the point of requiring these personnel to display evidence of comparing studies with themselves. To ensure that this intent is retained in the final version of the standard it is suggested that this note or some derivative be placed somewhere in body of the standard such as the definition of Interconnected Element or under the requirements.
Yes
Yes
Yes
Yes
Regarding the applicability to the Generator Operator, the registered function of the Generator Operator could exist as a centralized corporate function as well as a remote function at the generation station. The requirements are probably aimed at the remote function, but if the corporate function embodies an electrical design group that is “familiar” with the protection systems “in their area”, is that sufficient for compliance? The draft includes a description of applicable “Facilities”, but the question still applies.
Yes
The requirement still calls for “familiarity” with the protection systems “in their area”. The extent of “familiarity” comes into question as well as the question of what constitutes “their area”. The newly crafted Measurement attempts to give some detail as to what that means. But if training is the expected means of achieving compliance, why not just require the training? And if training is expected, then the scope of that training should be related to application of a systematic approach to training, not a scope identified by the SDT, or an area arbitrarily selected by the auditors.
Please change Figures 3 and 4 so that “Interconnected Element” is adjacent or points to the line between Breaker C and the point of connection (tap point) on the line between Breakers A and B. It clarifies these examples by having the Figures align with your wording. (The Figures presently imply that the line between Breakers A and B is the “Interconnected Element”.) The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual

Mike Hirst
Cogentrix Energy Power Management, LLC
Agree
North American Generator Forum (NAGF) Standard Review Team (SRT)
Individual
Jim Howard
Lakeland Electric
Agree
FMPA (agree with their comments)
Individual
Brian J Murphy
NextEra Energy
No
The end of the sentence should read: . . . . desired sequence and time during Faults.
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Larry Watt
Lakeland Electric
Agree
Lakeland Electric concurs with FMPA comments.
Individual
Anthony Jablonski
ReliabilityFirst

No
a. ReliabilityFirst requests clarification on the term “Interconnected Element.” First, is the term “facilities” referring to the NERC Glossary of Terms defined term “Facility”? If so, this term needs to be capitalized. Furthermore, if this is the intent, with a Facility being defined as “a set of electrical equipment that operates as a single Bulk Electric System Element”, there seems to be no need to add the term “BES” to the beginning of the definition. ReliabilityFirst recommends capitalizing the term “facility” and deleting the term “BES” from the definition.
No
a. ReliabilityFirst believes the shift from 48 calendar months to 60 calendar months is an excessive amount of time to allow an entity to perform a Protection System Coordination Study (PSCS). With the effective date of the standard being 12 months beyond the date that it is approved by applicable regulatory authorities, this is essentially giving entities over six years to perform their initial study, for equipment that previously had no study performed. Furthermore, from a reliability perspective, this coordination is most likely already occurring in some capacity, when the interconnection is made, and entities should not require this excessive timeframe to perform the study (i.e., as quoted from the SDT: “…there is no evidence of widespread miscoordination of Protection Systems associated with Interconnected Elements…”). ReliabilityFirst recommends a 24 calendar month implementation timeframe to limit any potential reliability issues as a result of shortcomings in the existing set of Standards.
ReliabilityFirst offers the following comments for consideration: 1) Requirement R1, Part 1.2 - ReliabilityFirst recommends converting the parenthetical last sentence “(including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed)” into four separate and distinct sub-parts. Separating these out will clearly spell out to the applicable entity and compliance auditors the specific items which are required to be provided. Listed below is an example for consideration: 1.2.1 Protection Systems Reviewed 1.2.2 Associated fault currents 1.2.3 Identified issues 1.2.4 Proposed revisions or actions 2) Requirement R2, Part 2.2 - Within both the clean and redline version of the posted draft standard, the equation referenced at the end of Requirement R2, Part 2.2 is inadvertently missing and therefore needs to be added back into the requirement.
Group
JEA
Tom McElhinney
Yes
No

Most of the standard (R1.2, R2.2.1, R3 & R4) should not be applicable to a Registered Entity that represents multiple functional entity where the same system protection group has responsibility for the protection of their entire control area.
Yes
Yes
Yes
Yes
Yes
Individual
John Allen
City Utilities of Springfield, Missouri
Agree
Southwest Power Pool Standards Review Group
Individual
Daniela Hammons
CenterPoint Energy
The draft for PRC-027-1 states: “records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” CenterPoint Energy considers the proposed requirements to be too prescriptive for Protection System coordination when it has not been identified as a reliability issue and expects such requirements would provide little, if any, reliability benefits. We believe the majority of existing Interconnected Facilities have time-proven and fault-proven Protection System set points and that newer facilities, including replacement relay panels, are commissioned utilizing appropriate coordination studies that include necessary interaction between interconnected entities. CenterPoint Energy recommends reevaluating the need for this standard with

consideration that this subject area could instead be addressed by continuing to focus on misoperation analysis and through best practices initiatives.
Group
Tacoma Power
Chang Choi
No
Suggest removing the word ‘components.’ A Protection System operates together. If the SDT elects to retain the word ‘components,’ clarification of the intent of this word in this context is requested.
No
There is some concern about the language in part b of the proposed definition of an Interconnected Element. In some cases, a Registered Entity may have one engineering group that is responsible for all Protection Systems, regardless of registered function. Part b of the proposed definition seems to suggest that documented PSCSs, including coordination activities, could be required by proposed PRC-027-1 even if the same engineering group is responsible for all Protection Systems associated with the Interconnected Element. A distinction should be drawn between a Registered Entity in which one engineering group is responsible for Protection Systems associated with its DP, GO, and TO functions, as applicable, and another Registered Entity in which a different engineering group is responsible for Protection Systems associated with its DP vs. GO vs. TO functions, as applicable.
Yes
Yes
Yes
Should the Flowchart be updated to reflect the course of action if an entity rejects the results and suggests modifications to resolve any identified coordination issues?
No
The level of detail in the Applicability section appears to be inconsistent with the language in M1 “…training in basic relaying…” For this reason, it is recommended not to include the ‘Facilities’ portion.
Yes
Tacoma Power appreciates the efforts of the SDT. This is a difficult process and topic on which to standardize. It would help, especially for the Flowchart, if R1.1.3 could be separated into a revised R1.1.3 “according to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1; or technically justify why such a study is not required” and a new R1.1.4 “within six calendar months of being notified of a change as described in Requirement R3, Part 3.3; or technically justify why such a

study is not required." In R3.1, the language "or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s)" appears to be very open-ended with respect to the second, third, and fourth bullets under R3.1. In theory, any impedance change within an entity's system could qualify, which brings into question potential overlap between R2 to address incremental changes and R3.1. R3.1 should establish a brighter line for what triggers an entity to begin coordination activities for proposed impedance changes not at an existing or new Facility associated with the Interconnected Element. In other words, at what point is an impedance change considered an incremental change and, therefore, applicable to R2, as opposed to R3.1? In the Flowchart, the arrows are confusing above the decision diamond "(R1.1.3) Is a new PSCS required?" Referring to M2, M5, M7, and M8, is any confirmation of receipt required in order to demonstrate that a responsible entity 'provided' the information? It is recommended that evidence of receipt not be required to demonstrate that an entity 'provided' information applicable to these measurements. Referring to the Application Guidelines, Figure 5 and associated discussion, the introductory paragraph statement "in Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be check for coordination with Generator Owner T" appears to contradict the discussion on page 39 of 40 of the redlined copy of PRC-27-1.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Yes
Yes
Yes
Yes
No
Since there are no guidelines on who "applicable personnel" are, and there are no guidelines on what type of training is required and how often, this measure serves little purpose should be removed. Measures and VSLs are overly complex and will be difficult to effectively track as written.
1) PRC-027-1 R3.2 has a deadline based on the date of receiving a request. There should more

details regarding what constitutes receiving a request. If informal channels are used, there may be disagreement about whether the 30 day deadline was met. The complexity of this standard becomes all the more evident when looking at ways to implement and track all the measures. For many of the measures, the only practical way to capture time frames is to tie communications with an interconnected entity to a task within an established schedule. Communications with interconnected entities will likely need to become more limited and formal to become more trackable. Bringing tractability to emails and other communications for evidence will be a significant issue, with the need to capture communications of out-side resources performing studies as well as the use of secure email requiring tedious offloading or screen captures of communications from secure servers. It would be recommended that acceptable evidence demonstrating the time frames should allow for documented processes along with activity schedules providing start and completion dates. More detailed evidence should be signed and verified studies, which indicate that validated models and remote settings have been utilized in the analysis. Here are our specific recommendations by requirement and measure: a) Requirement R1- R1.1.3- It would be recommended to be consistent with the time frame as specified in 1.1.2 and change the specified calendar months to read “or within 12 calendar months of being notified of a change as described in Requirement R3, Part 3.3.” M1, M2 - Acceptable evidence demonstrating time frames should allow for documented processes along with activity schedules providing start and completion dates. (VSL) Violation Security Levels- Each security level should provide consistent time frames to avoid confusion in tracking. b) Requirement R2 – R2.2- Allowance should be made to allow for tracking of fault level trends at the bus based on a 10% change in fault level for the year of the coordination study. M5 - Acceptable evidence demonstrating time frames should allow for documented processes along with activity schedules providing start and completion dates. (VSL) Violation Security Levels- Each security level should provide consistent time frames to avoid confusion in tracking. c) Requirement R3 – M7 – A data request should indicate that it is being made per requirement R3 of PRC-027 to be measured under M7. M6, M7, M8- Acceptable evidence demonstrating time frames should allow for documented processes along with activity schedules providing start and completion dates. d) Requirement R4— R4- Study submittals should be required to stipulate that the study is being submitted per requirement R4 of PRC-027 to be measured under M9. M9, M10- Acceptable evidence demonstrating that the time frames have been met should allow for documented processes along with activity schedules providing start and completion dates. 2) 4.2.1 Applicability: For Generator Owners, many elements that are covered under the PRC-019, PRC-024 and PRC-025 (and future Phase 3 Loadability Standards) also fall under the Facilities Section of this draft of PRC-027-1, as the functions exist for the sole purpose of allowing coordination for faults to clear external to the generator. The elements covered by other standards should be excluded from applicability, in order to avoid a double jeopardy situation. Instead, we recommend that a list of applicable elements be identified. Typical functions are identified below. We believe these to be the only functions applicable to the standard as far as a GO is concerned. - Ground Time Overcurrent Relay – (Directional Towards the System) (51G) - Neutral Time Overcurrent Relay – (Directional Towards the System) (51N) - Ground Directional Time Overcurrent Relay – Directional Toward Transmission System (67G) - Negative Phase Sequence Overcurrent (46) In addition, please

consider adding a list of excluded elements, such as these: - Phase Distance (21) (Covered under PRC-025) - Volts/Hz (24) (Covered under PRC-024) - Undervoltage (27) (Covered under PRC-024) - Reverse Power (32) (Not applicable to standards as it is protection for the generator) - Loss of Field (40) (Covered under PRC-019) - Inadvertent Energization (50/27) (Not applicable to standards as it is protection for the generator) - Breaker Failure (50BF) (Not applicable to standards as it is protection for the generator) - Phase Time Overcurrent Relay (51) (Covered under PRC-025) - Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Covered under PRC-025) - Phase Time Overcurrent Relay – Voltage Controlled (51V-C) (Covered under PRC-025) - Overvoltage (59) (Covered under PRC-024) - Field Overvoltage (59E) (Covered under PRC-019) - Stator Ground (59GN/27TH/64S) (Not applicable to standards as it is protection for the generator) - Field Ground (64F) (Not applicable to standards as it is protection for the generator) - Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Covered under PRC-025) - Field Overcurrent (76E) (Covered under PRC-019) - Out of Step (78) (Covered under Future Phase 3 Loadability Standards) - Frequency (81) (Covered under PRC-024) - Differential (87) (Not applicable to standards as it is protection for the unit) Alternatively, perhaps a table listing excluded elements could be added to the back of the standard, and referenced in the 4.2.1 Applicability section. Here is an example of what 4.2.1 might look like: “4.2.1 Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements with the exclusion of the elements listed in table XXX. “ 3) Regarding R2 M3 - Our technical justification to exempt the above excluded elements is: a) duplication in applicability to other standards, and b) the type of fault. Mandating technical justification beyond these two points puts an unnecessary burden on industry resources.
Individual
Mary Downey
City of Redding
Agree
SMUD
Individual
Tony Kroskey
Brazos Electric Power Cooperative
Agree
ACES Power Marketing
Individual
Bob Thomas and Kevin Wagner
Illinois Municipal Electric Agency
Yes
No

Illinois Municipal Electric Agency suppports comments submitted by Florida Municipal Power Agency.
No
Illinois Municipal Electric Agency suppports comments submitted by Florida Municipal Power Agency.
Yes
Yes
Illinois Municipal Electric Agency (IMEA)supports comments under Question 8 submitted by the SERC EC Protection and Control Subcommittee. Also,IMEA requests that Figure 3 be modified or a separate figure be included to clarify guidelines for DP systems that include only non-BES generation. IMEA also requests that Applicability Section 4.2.1 be revised to prevent inconsistency with the FERC-approved interpretation of transmission Protection System as specified in PRC-005-1b. Very specific attention/consideration needs to be given to avoiding unnecessary expansion of applicability to facilities owned by small Distribution Providers; i.e., unnecesarry expansion of scope to protective devices owned by a DP that have no potential adverse impact on the BES. Both FERC and NERC have stated the need to minimize impacts on small entity resources.
Individual
Bret Galbraith
Seminole Electric Cooperative Inc.
(1) In proposed PRC-027-1 R2, Seminole believes that the Reliability Coordinator (RC) should have the responsibility of performing any studies or analyses and the distribution of those studies/analyses required under R2 instead of the Transmission Owner (TO). In peninsular Florida, the RC has access to the data needed for the analyses and having a single entity perform the analyses and distribution will assure uniformity across the region. (2) In proposed PRC-027-1 R2-2.2.1., Seminole believes the 10% threshold for fault current is too low, as this percent change occurs daily. Seminole recommends the 10% threshold value be increased to 20% for fault current. (3) In proposed PRC-027-1 R2, is the 10% change in fault current study

based on the individual TO's system contribution as an island at the interconnection bus, or does it include all other interconnection that border the TO's system that could provide fault current, i.e., how many buses out from the TO's other interconnections does the study require for determining available fault current? (4) In proposed PRC-027-1 R2, Seminole believes that the requirements and guidelines for the Protection System Coordination Study (PSCS) need to be more specific and give additional detailed methodology. (5) In proposed PRC-027-1 R3-3.1, it should be noted that current and voltage ratio changes do not necessarily indicate a change in the protection system if the protective relay set points are adjusted accordingly. Therefore, R3-3.1 should be revised to reflect that certain ratio changes do not require notification.

Consideration of Comments

Project 2007-06 System Protection Coordination
PRC-027-1

The Project 2007-06 Drafting Team thanks all commenters who submitted comments on the PRC-027-1 standard for System Protection Coordination. The standard was posted for a 30-day formal comment period from June 4, 2013 through July 3, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 67 sets of responses, including comments from approximately 196 different people from approximately 130 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Summary Consideration of all Comments Received

PRC-027-1

Definitions:

Interconnecting Element:

Based on comments, the drafting team made two minor changes to the previous term "Interconnected Element". First, the term was changed to "Interconnecting Element", and secondly the words "owned by" were moved to the beginning of both parts (a) and (b). The new definition is:

"Interconnecting Element"

A Bulk Electric System (BES) Element that electrically joins Facilities:

a) owned by separate Registered Entities, or

b) owned by the same Registered Entity that represents multiple functional entity responsibilities

(Transmission Owner, Generator Owner, or Distribution Provider)

Protection System Coordination Study:

Based on comments, the drafting team made two minor changes to the definition of "Protection System Coordination Study". First, "that demonstrates" was replaced with "documenting that," and secondly the word "desired" was replaced with "intended." The new definition is:

"Protection System Coordination Study"

A study documenting that existing or proposed Protection Systems operate in the intended sequence for clearing Faults.

Purpose:

Commenters suggested several minor modifications to the Purpose statement. Based on discussions related to these suggestions, the drafting team revised the Purpose to read:

"To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults."

Applicability:

To emphasize the fact that a subset of Applicability section 4.1.3 "Distribution Provider" would be applicable to this standard, the drafting team added the parenthetical phrase "(that own Protection Systems identified in the Facilities section 4.2 below)"

Based on comments, the drafting team removed section 4.2.1 from section 4.2 Facilities for clarity. It now states:

Protection Systems:

a) installed for the purpose of detecting Faults on Interconnecting Elements, and

b) that require coordination for isolating those faulted Elements

Background:

General revisions were made to provide clarity and remove duplicitous information.

Based on feedback from NERC legal staff, the "Other Aspects of Coordination of Protection Systems Addressed by Other Projects" section was moved from the Background section to the Roadmap section.

Requirements and Rationale boxes:

Based on the change to the term "Interconnecting Element" and some clarifying language suggested by stakeholders, minor revisions were made to each requirement and the corresponding Rationale boxes. Also based on stakeholder comments, an additional requirement (R5) was added for clarity.

Requirement R1:

Based on stakeholder comments, the drafting team separated Requirement R1.1, Part 1.1.3 because of the referenced requirements and the associated time frames. Requirement R1.1, Part 1.1.3 now references only Requirement R3, Part 3.1; and reads:

"According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or technically justify why such a study is not required."

New Requirement R1.1, Part 1.1.4 now references only Requirement R3, Part 3.3; and reads:

"Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3, or technically justify why such a study is not required."

Requirement R2:

The drafting team removed the provision that the Transmission Owner could provide a technical justification for not conducting the 60 month Fault current review because of the reliability benefit associated with providing updated Fault current information to the other Protection System owners for model validation and ultimately proper coordination.

Requirement R3:

Based on stakeholder comments, the drafting team inserted the word "permanent" and made minor clarifying edits to Requirement R3, Part 3.3; it now reads:

"Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."

Requirement R4:

Based on stakeholder comments, the drafting team separated Requirement R4 into two requirements. The modified Requirement R4 mandates that owners, who receive either a summary of the results of a Protection System Coordination Study (PSCS) or a technical justification, review and respond to the sender, acknowledging the review and noting whether or not any coordination issues were identified. Requirement R4 retains the “90 calendar days” or “agreed-upon schedule” time frames for performing the reviews.

Requirement R5:

The new Requirement R5 mandates that any identified coordination issues be addressed prior to the implementation of any changes or additions to the Protection System(s) associated with the Interconnecting Element.

Measures:

Measure M3 was eliminated because the option of providing a technical justification for not performing a short circuit study was removed.

The other measures were renumbered and/or modified to be consistent with the revised requirements.

Evidence Retention:

The drafting team modified the language for consistency.

VSLs:

The drafting team modified the VSLs for consistency with the revised requirements.

Guidelines and Technical Basis:

Complementary changes were made to the Guidelines and Technical Basis corresponding to all changes to the standard.

The drafting team updated the process flow chart to align with the revised requirements and made minor edits to the Example Process.

In the introductory section for the Diagrams, the drafting team included an additional note for clarity.

Based on comments, the Figures and associated descriptions were modified to provide more clarity.

The drafting team revised the description associated with Figure 4 to clarify that it depicts an example of a configuration that is not applicable to this standard because the Distribution Provider does not have a Protection System installed for the purpose of detecting Faults on BES Elements.

Unresolved Minority Views:

A few commenters continue to suggest that there is no need for this standard because there is no evidence that suggests there is a lack of Protection System coordination. The drafting team responded that the standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.

Some commenters disagree with part "b" in the proposed definition of Interconnecting Element that reads: A BES Element that electrically joins Facilities owned by the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner) because of compliance concerns, primarily for vertically integrated utilities. However, the drafting team contends part "b" is necessary because in some vertically integrated utilities, coordination related to different functional entities may not be performed by the same protection group. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities."

Some commenters disagree with the various time frames associated the requirements. The drafting team responded that the specified time frames are relevant and appropriate for each of the requirements, and also reminded the commenters that the process flow chart in the Guidelines and Technical Basis section of the standard illustrates the relationship between the requirements.

A few commenters continue to suggest that Generator Owners (GO) should be excluded from performing a Protection System Coordination Study (PSCS) after being notified by the Transmission Owner of a 10% or greater change in Fault current at an interconnecting bus. The drafting team responded that a GO could provide a technical justification explaining why changes in bus Fault current do not affect its coordination rather than performing a Protection System Coordination Study (PSCS), and that a previous technical justification could be reused provided it is still valid.

A few commenters continue to disagree with the 10% deviation trigger in Requirement R2. The threshold of 10% was selected based on the experience of drafting team members, discussions with members of various regional protection and control committees, and the recognition that there are margins of error in models and in protection system accuracies. The drafting team contends that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. No change was made to the standard.

A few commenters continue to suggest that mutual agreement on Protection System settings between owners will sometimes not be achieved and have compliance concerns associated this fact. The drafting team revised Requirement R4 replacing the language that specified either "accepting" or "rejecting" the summary results of a PSCS with confirming that the summary of results or the technical justification were reviewed and whether or not any identified coordination issues were noted. Requirement R5 mandates that any identified coordination issues must be addressed prior to implementation of any changes or additions to the Protection System(s) associated with the Interconnecting Element.

PRC-001-3

The Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027 in June of 2013 for comment and ballot. As part of the Draft 3 posting, the SPCSDT recommended retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults. In preparing the initial posting package for Draft 4 of PRC-027-1, the SPCSDT noted that the retirement of the remaining Requirement R1 would be coordinated through the Project 2010-01 Training project. After NERC staff review, it was determined that the retirement of PRC-001-2 Requirement R1 was outside the scope of the SAR of either project. Because Requirement R1 of PRC-001-2 will not be retired in either current project, a modified version of PRC-001-3 reflecting the retirement of Requirements R2 and R3 is currently posted for stakeholder review. The modified Reliability Standard also reflects updates to the “Effective Dates” as well as Section “D. Compliance” to reflect current ERO language. Requirement R1 will remain unchanged. NERC standards staff is currently reviewing how to address the recommendations of the Independent Experts Review Panel to consolidate training requirements, including R1 of PRC-001-2, and industry concerns with Requirement R1. The ballot of PRC-001-3 is associated with the approval of PRC-027-1 and the implementation plan for this project.

Effective Date:

Updated to reflect current ERO language

Requirement R1:

Unchanged

Requirement R2:

Retired

Requirement R3:

Retired

Measure M1:

Eliminated

Compliance Enforcement Authority:

Updated to reflect current ERO language

Evidence Retention:

Updated to reflect current ERO language

VSLs:

Eliminated VSLs for Requirements R2 and R3

Index to Questions, Comments, and Responses

1. Based on stakeholder comments, the drafting team modified the Purpose of this standard to: "To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults." Do you agree with this Purpose? If not, please provide specific suggestions for improvement in the comment area. 20

2. The drafting team modified the proposed definition of Interconnected Element to read as follows: Interconnected Element: A BES Element that electrically joins facilities owned by: a) separate Registered Entities, or b) the same Registered Entity that repesents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner). Do you agree with the revised definition? If not please provide specific suggestions for improvement in the comment area. 31

3. In Requirement R1, the drafting team modified the time frame to allow entities 60 months to have a documented Protection System Coordination Study (PSCS) completed for each Interconnected Element if no PSCS exists. Note, the drafting team has allowed inclusion of all previously performed PSCS whose summary of results include, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. Do you agree with this revised time frame? If not, please provide specific suggestions for change in the comment area. 49

4. In Requirement R2, the drafting team modified the time frame to 60 months for either conducting a Fault current review or provide a technical justification as to why a Fault current review is not necessary. Do you agree with this revision to Requirement 2? If not, please provide specific suggestions for improvement in the comment area. 59

5. In Requirement R4, the drafting team has clarified the expectation of what a response to a review of the summary results of a Protection System Coordination Study should include. The options are as follows: • Accepting the results, or • Rejecting the results and suggesting modifications to resolve any identified coordination issues. Do you agree with this revision to Requirement R4? If not, please provide specific suggestions for improvement in the comment area. 67

6. The drafting team revised the Applicability section of PRC-001-2 to clarify which Protection Systems are applicable to Requirement R1. (The "Facilities" portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.) Do you agree with this revision to the Applicability? If not, please provide specific suggestions for improvement in the comment area. 80

7. The drafting team provided a measure to accompany Requirement R1 of PRC-001-2. (The language in the measure was modeled after the existing language in the RSAW for PRC-001-2.) Do you agree with this measure? If not, please provide specific suggestions for improvement in the comment area. 89

8. If you have any other comments that you haven't already provided in response to the above questions, please provide them here. 98

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Frank Gaffney	Florida Municipal Power	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Greg Campoli, Chair	ISO RTO Council Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Matt Goldberg	ISONE	NPCC	2

NERC

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

2. Ben Li	IESO	NPCC	2
3. Lori Spence	MISO	MRO	2
4. Charles Yeung	SPP	SPP	2
5. Matt Morais	ERCOT	ERCOT	2
6. Ali Mehremadi	CAISO	WECC	2

3.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Ben Wu	Orange and Rockland Utilities	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1
10.	Christina Koncz	PSEG Power LLC	NPCC	5
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Donald Weaver	New Brunswick System Operator	NPCC	2
21.	Wayne Sipperly	New York Power Authority	NPCC	5

4.	Group	David Thorne	Pepco Holdings	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Carl Kinsley	Delmarva Power & Light Co.	RFC	1, 3

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

2. Alvin Depew	Pepco Holdings Inc.	RFC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Michael Lowman	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils		RFC	1
2. Lee Schuster		FRCC	3
3. Dale Goodwine		SERC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Larry Raczkowski	FirstEnergy Corp	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. William Smith	FirstEnergy Corp	RFC	1
2. Cindy Stewart	FirstEnergy Corp	RFC	3
3. Doug Hohlbaugh	Ohio Edison	RFC	4
4. Ken Dresner	FirstEnergy Solutions	RFC	5
5. Kevin Querry	FirstEnergy Solutions	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Morgan Senkal	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Dean Bender	BPA Transmission SPC Technical Services	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Randi Heise	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Michael Crowley	Electric Transmission	SERC	1, 3
2. Jeff Bailey	Nuclear	SERC	5
3. Chip Humphrey	Fossil & Hydro	RFC	5
4. Sean Iseminger	Fossil & Hydro	SERC	5
5. Connie Lowe	Dominion	SERC	1, 3, 5, 6
6. Mike Garton	Dominion	NPCC	1, 3, 5, 6
7. Louis Slade	Dominion	RFC	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Kathi Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	DTE Electric	RFC	3, 4, 5
2. Dan Herring	DTE Electric	RFC	3, 4, 5
3. Al Eizans	DTE Electric	RFC	3, 4, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Group	Patrick Brown	Essential Power, LLC					X					
11.	Group	John Allen	Rochester Gas & Electric	X									
12.	Group	Joseph DePoorter	Madison Gas and Electric Company	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
4.	Dave Szulczewski	DTE Electric	RFC	3, 4, 5

10. Group — Patrick Brown — Essential Power, LLC

	Additional Member	Additional Organization	Region	Segment Selection
1.	Allen Schriver	NexrEra		5
2.	Steve Berger	PPL Susquehanna, LLC		5
3.	Joe Crispino	PSEG Fossil, LLC		5
4.	Pamela Dautel	IPR-GDF Suez Generation NA		5
5.	Dan Duff	Liberty Electric Power		5
6.	Mikhail Falkovich	PSEG		5
7.	Gary Kruempel	MidAmerican Energy Company		5
8.	Katie Legates	American Electric Power		5
9.	Don Lock	PPL Generation, LLC		5
10.	Joe O'Brien	NIPSCO		5
11.	Dana Showalter	E.ON		5
12.	William Shultz	Southern Company		5
13.	Mark Young	Tenaska, Inc		5

11. Group — John Allen — Rochester Gas & Electric

	Additional Member	Additional Organization	Region	Segment Selection
1.	Raymond Kinney	New York State Electric & Gas	NPCC	1
2.	Joseph Turano	Central Maine Power	NPCC	1

12. Group — Joseph DePoorter — Madison Gas and Electric Company

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.			NA - Not Applicable	
3.	Dan Inman	MPC	MRO	1, 3, 5, 6
4.	Dave Rudolph	BEPC	MRO	3, 5, 6
5.	Kayleigh Wilkerson	LES	MRO	1, 3, 5, 6
6.	Jodi Jenson	WAPA	MRO	1, 6
7.	Joseph DePoorter	MGE	MRO	3, 4, 5, 6
8.	Ken Goldsmith	ALTW	MRO	4
9.	Lee Kittleson	OTP	MRO	1, 3, 5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

10. Mahmood Safi	OPPD	MRO	1, 3, 5, 6
11. Marie Knox	MISO	MRO	2
12. Mike Brytowski	GRE	MRO	1, 3, 5, 6
13. Scott Bos	MPW	MRO	1, 3, 5, 6
14. Scott Nickels	RPU	MRO	4
15. Terry Harbour	MEC	MRO	3, 5, 6
16. Tom Breene	WPS	MRO	3, 4, 5, 6
17. Tony Eddleman	NPPD	MRO	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	David Dockery	Associated Electric Cooperative, Inc.	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Central Electric Power Cooperative		SERC	1, 3
2. KAMO Electric Cooperative		SERC	1, 3
3. M & A Electric Power Cooperative		SERC	1, 3
4. Northeast Missouri Electric Power Cooperative		SERC	1, 3
5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Robert Rhodes	Southwest Power Pool		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springifeld	SPP	1, 4
2.	Joe Border	Board of Public Utilities, City of McPherson, KS	SPP	NA
3.	Greg Froehling	Rayburn Country Electric Cooperative	SPP	3
4.	Louis Guidry	Cleco Power	SPP	1, 3, 5
5.	Greg Hill	Nebraska Public Power District	MRO	1, 3, 5
6.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
7.	Kyle McMenamin	Xcel Energy	SPP	1, 3, 5, 6
8.	James Nail	City of Independence, Power & Light Department	SPP	3
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
10.	Sean Simpson	Board of Public Utilities, City of McPherson, KS	SPP	NA

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15. Group	Mary Jo Cooper	Cooper Compliance Corp	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Ken Dize	Salmon River Electric Coop	WECC	1, 3

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

2. Colin Murphey	City of Ukiah	WECC	3
3. Angela Kimmey	Pasadena Water and Power	WECC	1, 3
4. Cynthia Whitchurch	Alameda Municipal Power	WECC	3
5. Blaine Ladd	California Pacific Electric Company	WECC	3
6. Elizabeth Kirkley	City of Lodi	WECC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16. Group	Brent Ingebrigtson	LG&E and KU Services	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2. Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Affiliates	RFC	5
3.		WECC	5
4. Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
5.		NPCC	6
6.		SERC	6
7.		SPP	6
8.		RFC	6
9.		WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17. Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. DeWayne Scott		SERC	1
2. Ian Grant		SERC	3
3. David Thompson		SERC	5
4. Marjorie Parsons		SERC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18. Group	David Greene	SERC RRO										

Additional Member	Additional Organization	Region	Segment Selection
1. Paul Nauert	Ameren		
2. Bridget Coffman	Santee Cooper		
3. Steve Edwards	Dominion, Va. Power		
4. Phil Winston	Southern Company Services		
5. Greg Davis	GTC		
6. Russ Evans	SCE&G		
7. David Greene	SERC RRO		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	John Babik		FRCC	3
3.	Garry Baker		FRCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Group	Chang Choi	City of Tacoma	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Travis Metcalfe	Tacoma Public Utilities	WECC	3
2.	Keith Morisette	Tacoma Public Utilities	WECC	4
3.	Chris Mattson	Tacoma Power	WECC	5
4.	Michael Hill	Tacoma Public Utilities	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				
22.	Individual	Bob Steiger	Electric Reliability Compliance	X		X		X	X	X			
23.	Individual	Stephanie Monzon	PJM Interconnection		X								
24.	Individual	Erika Doot	Bureau of Reclamation	X				X				X	
25.	Individual	Pamela Hunter	Southern Company	X		X		X	X				
26.	Individual	Rowell Crisostomo	ATCO Electric	X									
27.	Individual	Dan Roethemeyer	Dynegy					X					
28.	Individual	John Falsey	Invenergy LLC					X					
29.	Individual	John Bee	Exelon and its Affiliates	X		X		X					
30.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
31.	Individual	Michael Falvo	Independent Electricity System Operator		X								
32.	Individual	NICOLE BUCKMAN	ATLANTIC CITY ELECTRIC COMPANY			X							
33.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
34.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
35.	Individual	Mark Yerger	Potomac Electric Power Company			X							
36.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
37.	Individual	Don Jones	Texas Reliability Entity										X
38.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
39.	Individual	Michael Moltane	ITC	X									
40.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
41.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
42.	Individual	Jonathan Meyer	Idaho Power Co.	X									
43.	Individual	Bill Middaugh	Tri-State G &T	X									
44.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
45.	Individual	Karen Webb	City of Tallahassee - Electric Utility					X					
46.	Individual	Bill Fowler	City of Tallahassee			X							
47.	Individual	Scott Langston	City of Tallahassee	X									
48.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
49.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
50.	Individual	Richard Vine	California ISO		X								
51.	Individual	David Jendras	Ameren	X		X		X	X				
52.	Individual	RoLynda	Shumpert	X		X		X	X				
53.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
54.	Individual	Jack Stamper	Clark Public Utilities	X									
55.	Individual	Joe Tarantino	SMUD	X		X	X	X	X				
56.	Individual	Mike Hirst	Cogentrix Energy Power Management, LLC					X					
57.	Individual	Jim Howard	Lakeland Electric	X		X		X	X				
58.	Individual	Brian J Murphy	NextEra Energy	X		X		X	X				
59.	Individual	Larry Watt	Lakeland Electric	X		X		X	X				
60.	Individual	Anthony Jablonski	ReliabilityFirst										X
61.	Individual	John Allen	City Utilities of Springfield, Missouri	X			X						
62.	Individual	Daniela Hammons	CenterPoint Energy	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
63.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
64.	Individual	Mary Downey	City of Redding			X	X	X			X		
65.	Individual	Tony Kroskey	Brazos Electric Power Cooperative	X									
66.	Individual	Bob Thomas and Kevin Wagner	Illinois Municipal Electric Agency				X						
67.	Individual	Bret Galbraith	Seminole Electric Cooperative Inc.			X	X	X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Comments of "Entity Name"
Brazos Electric Power Cooperative	ACES Power Marketing
Invenergy LLC	Essential Power, LLC
City of Tallahassee - Electric Utility	Florida Municipal Power Agency (FMPA)
City of Tallahassee	FMPA
Lakeland Electric	FMPA (agree with their comments)
Lakeland Electric	Lakeland Electric concurs with FMPA comments.
Cogentrix Energy Power Management, LLC	North American Generator Forum (NAGF) Standard Review Team (SRT)
Rochester Gas & Electric	NPCC
Potomac Electric Power Company	Pepco Holdings Inc, and Affiliates

Organization	Supporting Comments of "Entity Name"
ATLANTIC CITY ELECTRIC COMPANY	Pepco Holdings Inc. and Affiliates
Delmarva Power & Light Company	Ppeco Holdings Inc. and Affiliates
Shumpert	SERC PCS
Tennessee Valley Authority	SERC Protection & Control Subcommittee(PCS)
City of Redding	SMUD
City Utilities of Springfield, Missouri	Southwest Power Pool Standards Review Group

1. **Based on stakeholder comments, the drafting team modified the Purpose of this standard to: “To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.” Do you agree with this Purpose? If not, please provide specific suggestions for improvement in the comment area.**

Summary Consideration:

Several commenters suggested changes to the Purpose statement. Among them were: change “desired” to “acceptable”, remove the words “coordinate” and “components”, change “coordinate” to “ensure”, add “to clear faults” to the end of the statement, and add “time delayed” before Protection Systems. Based on discussions related to these suggestions, the drafting team revised the Purpose as follows: “To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.”

One commenter suggested changing the title of the standard to “Protection System Coordination for Interconnected Elements”. The drafting team did not make the suggested change. The drafting team contends that the title of the standard should remain “Protection System Coordination for Performance During Faults.” The Purpose and Applicability effectively limit the scope of the standard.

Several commenters referenced PRC-001 rather than the Purpose statement of PRC-027. The drafting team referred them to the response for questions #6 and #7 regarding PRC-001.

Organization	Yes or No	Question 1 Comment
Public Service Enterprise Group	No	As a Results-Based Standard, ?coordinate? should be removed from the Purpose. We suggest that the Purpose should be ?To ensure that Protection Systems involving Interconnected Elements operate in the desired sequence during Faults.?
Response: Thank you for your comment. The drafting team contends that “coordinate” is a necessary part of the Purpose for this Results-Based Standard. The last clause of the Purpose (“such that Protection System components operate in the desired sequence during Faults”) is meant to help define “coordinate” when applied to Protection Systems for Interconnecting Elements. Based on overall stakeholder comments, the Purpose statement was modified to: “To coordinate Protection Systems for Interconnecting Elements, such that Protection System		

Organization	Yes or No	Question 1 Comment
components operate in the intended sequence during Faults.”		
Wisconsin Electric Power Company	No	Change "in the desired sequence" to "in an acceptable sequence". This better reflects the compromises that may be required by the different entities owning protection systems on an Interconnected Element.
Response: Thank you for your comment. Based on overall stakeholder comments, the Purpose statement was modified to: “To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.”		
Exelon and its Affiliates	No	ComEd believes that the definition should be revised to read ?To coordinate time-delayed Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.?
Response: Thank you for your comment. Coordination includes consideration of more than time-delayed elements, e.g. relay reaches and sensitivities of relay pickups. Based on overall stakeholder comments, the Purpose statement was modified to: “To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.”		
DTE Electric	No	Comments: Since the main purpose of this standard is to assure coordination of BES Interconnected Elements, there should be a provision included to require TOs to provide system fault data to DPs and GOs on a continuous basis so that coordination is performed on BES as well as non-BES elements using the latest data. If complete system fault study files are provided regularly (bi-annually?), projects can be completed using the latest data and not subject to re-evaluation when an update is provided by the TO every 60 months.
Response: Thank you for your comment. The drafting team does not agree that more frequent exchanges should be required by the standard. It is noted that each interconnected owner has the ability to request information at any time as part of Requirement R3, Part 3.2. The standard does not prohibit an owner from performing more frequent reviews.		

Organization	Yes or No	Question 1 Comment
LG&E and KU Services	No	Comments: The expression "the desired sequence" should be replaced with "an acceptable sequence," since the GO and TO may not have the same desires.
Response: Thank you for your comment. Based on overall stakeholder comments, the Purpose statement was modified to: “To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the <u>intended</u> sequence during Faults.”		
Florida Municipal Power	No	FMPA continues to believe the greater purpose is to ensure faults are cleared within their critical clearing times and that such consideration is greater than operating within the desired sequence. The same comment would apply to the definition of Protection System Coordination Study.
Response: Thank you for your comment. The drafting team contends the initial Protection System design and settings take into account the critical clearing times; and that operating within the intended sequence, as stated in both the Purpose and the definition of Protection System Coordination Study, ensures that Faults are cleared within their critical clearing times.		
Flathead Electric Cooperative, Inc.	No	In our area, there do not appear to be any issues with lack of protection system coordination and I am unsure if there is really a need for this standard. Their appear to be adequate protection systems standards noted in the "Other Aspects of Coordination of Protection Systems Addressed by Other Projects" section.
Response: Thank you for your comment. The standard is necessary to codify the roles and responsibilities of the interconnected owners to achieve coordination of Protection Systems that affect the reliability of the BES.		
ISO RTO Council Standards Review Committee	No	It seems like the scope of the standard as stated in the purpose statement can be misunderstood. Later in the proposed standard, the purpose is narrowed:?Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1.?The SDT should consider revising the purpose to reflect the scope of this standard, e,g. ?,,,operate in the desired sequence to CLEAR faults.?

Organization	Yes or No	Question 1 Comment
		PRC-001 issues; a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. This is a training requirement and as such, it should be transferred to the appropriate PER standards. The SRC supports the project for removing this requirement and moved into the PER standards..Providing training evidence does not demonstrate that the (operating personnel of) responsible entities are ?familiar with? the purpose and limitations of protection system schemes applied in its area. c. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. In response to comment submitted by some commenters, the SDT indicates that it ??recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.? We do not agree with this recommendation and hold the view that adding the issue to the NERC Issue Data Base is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT should propose a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee?s advice/direction for appropriate actions. We do not believe that the SDT or staff has brought this to the Standards Committee?s attention. Note that the Standards Committee is responsible for managing the standards development process and as such, can make an informed decision to either request the SDT to

Organization	Yes or No	Question 1 Comment
		expand its scope (via an amended SAR) to address the PRC-001 issue, or to ask staff or the SDT to prepare a separate SAR to address the issue in parallel. Leaving the PRC-001 hanging out there without a recourse is not a satisfactory solution, and may in fact harm reliability. We urge the SDT to take the initiative to bring this issue to the Standards Committee, with a proposal to amend the SAR or prepare a new SAR, or seek its advice and direction before continuing work on this project.]

Response: Thank you for your comments.

a) The drafting team contends the Purpose statement is clear. The title of the standard "Protection System Coordination for Performance During Faults" explains the scope of the standard. Consequently, the inclusion of "to clear faults" in the Purpose is unnecessary.

b and c) PRC-001 issues:

In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the "Effective Date" and "Compliance" sections of the standard is included with this fourth posting of PRC-027-1.

Organization	Yes or No	Question 1 Comment
SMUD	No	SMUD believes the purpose of this standard should state: ?To coordinate Protection Systems for Interconnected Connection to help ensure Protection

Organization	Yes or No	Question 1 Comment
		System components operate as expected for off-nominal conditions. We believe that the coordination is an effort to avoid misoperations a condition that may occur if the purpose statement is not met. We further believe that the coordination should not only cover a Fault condition but other intended operation that the protections scheme would cover, i.e. power swing, out of step tripping/blocking, etc.
Response: Thank you for your comment. The purpose of this standard is not to ensure Protection System components operate as expected for all off-nominal conditions. Protection System performance during Fault clearing is the only aspect of protection coordination addressed by Reliability Standard PRC-027-1. As stated in the Background section of this standard, Protection System responses to power swings, out of step tripping/blocking, etc. are being addressed in other NERC projects.		
City of Tacoma	No	Suggest removing the word ?components.? A Protection System operates together. If the SDT elects to retain the word ?components,? clarification of the intent of this word in this context is requested.
Response: Thank you for your comment. The NERC Glossary of Terms lists five types of Protection System components which must operate together to achieve the intended sequence during Faults. The word “components” was used in the Purpose because protective relays and their settings are not the only aspects of Protection Systems that can impact coordination.		
Southern Company	No	Suggest that "the desired sequence" be replaced with "an acceptable sequence" to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in an acceptable sequence during Faults. e.g. the GO and TO may not have the same desires.
Response: Thank you for your comment. Based on overall stakeholder comments, the Purpose statement was modified to: “To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.”		

Organization	Yes or No	Question 1 Comment
NextEra Energy	No	The end of the sentence should read: . . . . desired sequence and time during Faults.
Response: Thank you for your comment. Based on overall stakeholder comments, the Purpose statement was modified to: "To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults." The drafting team contends that intended sequence includes timing; therefore, adding "and time" to the Purpose would be redundant.		
Essential Power, LLC	No	The expression "the desired sequence" should be replaced with "an acceptable sequence," since the GO and TO may not have the same desires.
Response: Thank you for your comment. Based on overall stakeholder comments, the Purpose statement was modified to: "To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults."		
Northeast Power Coordinating Council	No	The wording is redundant. Coordinating Protection Systems mean operating in the desired sequence during faults. The Purpose should just read ?To coordinate Protection Systems for Interconnected Elements?.
Response: Thank you for your comment. The title of the standard "Protection System Coordination for Performance During Faults" explains the scope of the standard. The last clause of the Purpose "such that Protection System components operate in the intended sequence during Faults" supports the standard's title.		
Texas Reliability Entity	No	We suggest re-wording the second half of the purpose to say ?such that Protection System components operate in the desired sequence to properly isolate Faults?.
Response: Thank you for your comment. Based on overall stakeholder comments, the Purpose statement was modified to: "To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults." The drafting team contends operating in the intended sequence during Faults includes the idea of properly isolating Faults.		

Organization	Yes or No	Question 1 Comment
Ameren	Yes	(1) Ameren supports the SERC Protection & Control Subcommittee comments and hereby includes them by reference rather than repeating them all.
Response: Thank you for your comment. Please see the response to the (SERC RRO) comments submitted by the SERC Protection & Control Subcommittee.		
Dominion	Yes	1) The SPC standard drafting team created this result-based standard specifically directed toward Interconnected Facility applications by stating in the current draft that ?PRC027-1, with the stated pupose ?to coordinate Protection Systems for Interconnected Elements?.? . Also in Draft#3 the purpose now places emphasis on ?desired operating sequence? versus Element isolation. To align with this purpose, as previously suggested, we recommend that the title of this standard reflect the revised purpose and be renamed ?Protection System Coordination for Interconnected Elements?.
Response: Thank you for your comment. The drafting team contends the Purpose statement is clear. The title of the standard "Protection System Coordination for Performance During Faults" explains the scope of the standard. The Purpose statement supports the standard's title.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration (?ICLP?)agrees that the updated purpose statement is more appropriate for a BES Reliability Standard. The previous version sought to minimize the faulted elements ? which is a desirable goal in most cases, but may not be the highest priority where multiple interconnected entities are concerned. (Otherwise, the ironic result could be that local service is preserved at the expense of the wider-area system.) The intended Protection System design should predominate, as it will account for any such circumstances.
Response: Thank you for your support.		
Bureau of Reclamation	Yes	Reclamation appreciates and agrees with the drafting team?s clarification of the Purpose section. Reclamation agrees with the drafting team that it is more

Organization	Yes or No	Question 1 Comment
		important for Protection System components to ?operate in the desired sequence during Faults? than to have ?the least number of power system Elements? isolated to clear Faults as previously stated in Draft 2 of the Purpose section.
Response: Thank you for your support.		
Independent Electricity System Operator	Yes	We agree with the revised purpose statement, but reiterate our previous suggestion to add ?settings? after protection system (with the ?s? removed?) to make it clear that it is the coordination of the settings, not the design of protection systems. The SDT?s response to our previous comment indicates that: ??settings? are not the only aspect of Protection Systems that can impact the stated purpose.? We are unable to come up with any specific examples of what other parameters or actions associated with the Protection System of an Interconnection Element that would require coordination to ensure ?Protection System components operate in the desired sequence during Faults?. Please elaborate, or revise the purpose statement accordingly.
Response: Thank you for your comment. The coordination of settings is important to achieving the Purpose of the standard. However, the coordination of settings is not the only aspect of Protection Systems that can impact the ability to achieve the Purpose "to operate in the intended sequence during Faults." Notification of replacement with different types of protective relays, modification of protective relays, changes in communication systems, current transformer ratios and voltage transformer ratios are examples of Protection System information required to achieve coordination.		
Cooper Compliance Corp	Yes	We feel this is a good compromise to making the applicability the Transmission Planner. In our earlier comments we noted that we feel the drafting team should identify the Transmission Planner to be the entity who performs the studies as this is the function identified for the TP. The drafting team responded by stating they changed the Purpose.
Response: Thank you for your support.		

Organization	Yes or No	Question 1 Comment
Pepco Holdings	Yes	
Duke Energy	Yes	
FirstEnergy Corp	Yes	
Bonneville Power Administration	Yes	
Madison Gas and Electric Company	Yes	
Associated Electric Cooperative, Inc.	Yes	
Southwest Power Pool	Yes	
SERC RRO	Yes	
JEA	Yes	
PacifiCorp	Yes	
Electric Reliability Compliance	Yes	
PJM Interconnection	Yes	
Dynegy	Yes	
Manitoba Hydro	Yes	
American Electric Power	Yes	

Organization	Yes or No	Question 1 Comment
ITC	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Tri-State G &T	Yes	
Kansas City Power and Light	Yes	
Clark Public Utilities	Yes	
Xcel Energy	Yes	
Illinois Municipal Electric Agency	Yes	
California ISO		See associated SRC Comments
Response: Thank you for your comment. Please refer to the responses for SRC comments.		

2. **The drafting team modified the proposed definition of Interconnected Element to read as follows: Interconnecting Element: A BES Element that electrically joins facilities owned by: a) separate Registered Entities, or b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner). Do you agree with the revised definition? If not please provide specific suggestions for improvement in the comment area.**

Summary Consideration:

Based on comments, the drafting team made two minor changes to the previous term "Interconnected Element". First, the term was changed to "Interconnecting Element", and secondly the words "owned by" were moved to the beginning of both parts (a) and (b).

The new definition is:

Interconnecting Element:
A Bulk Electric System (BES) Element that electrically joins Facilities:
a) owned by separate Registered Entities, or
b) owned by the same Registered Entity that represents multiple functional entity responsibilities
(Transmission Owner, Generator Owner, or Distribution Provider).

Numerous commenters had concerns regarding part "b" of the definition of Interconnecting Element. The drafting team wants to clarify that the intent of this standard is to promote the coordination of Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults. The drafting team is not trying to be prescriptive how the coordination process is achieved regardless of the organizational structure of the applicable Registered Entity. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities."

Organization	Yes or No	Question 2 Comment
Nebraska Public Power District	No	Will there be an expectation that each entity involved with interconnected elements or facilities be pre-identified in any other documentation other than perhaps in each PSCS?

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. There is no requirement for pre-identification; however, it would be a reasonable expectation that an applicable entity would identify the Interconnecting Elements on its system.		
Dynegy	No	?Please provide more examples of interconnected elements, especially for a merchant generator. It?s not clear if the protection system study should address protection systems for just the generator breaker or also the generator step up transformer, unit auxiliary transformer, or the generator itself. Perhaps this information belongs in the Application Guideline.
Response: Thank you for your comment. Please see Figures #2 and #5 in the standard for examples of generator interconnections. Note that Figure #2 covers the large majority of generator interconnections. The Protection Systems included in the Applicability section of this standard are: Protection Systems: a) installed for the purpose of detecting Faults on Interconnecting Elements, and; b) that require coordination for isolating those faulted Elements.		
Bonneville Power Administration	No	1. In this new term, the use of ?interconnected? implies that the element is connected by another element, which is not what is intended. A more appropriate word would be ?interconnecting? as this indicates that this is the element that connects other elements. 2. The definition as written does not make sense because there is typically not an element that electrically joins facilities owned by separate registered entities. Instead, where the point of interconnection between separate registered entities is made, one entity will own the element on one side of the point of interconnection and the other entity will own the element on the other side of the point of interconnection. The change of ownership is made at a point, not through a commonly-owned element. Since all elements are owned by one entity or the other, there is no element that electrically joins the elements owned by the two entities and nothing that meets the definition provided for an Interconnected Element.3. Part B of the definition does not indicate which element is the Interconnected

Organization	Yes or No	Question 2 Comment
		Element in a system where the same registered entity represents multiple functions. Does this allow the entity to choose which element is considered to be the Interconnected Element? For example, if an entity is both a generator owner and transmission owner they will own all elements from the generator to and including the transmission system, with no change of ownership. There is no clear point where the generator function stops and the transmission function begins. Which element will be considered to be the Interconnected Element and required to comply with this standard?
Response: Thank you for your comment. 1. The drafting team agrees and accepts your suggestion; the term is now "Interconnecting Element" 2. The Interconnecting Element is the Bulk Electric System (BES) Element being protected by the Protection Systems requiring coordination. Please reference the figures in the Guidelines and Technical Basis section of the standard for various examples of Interconnecting Elements.		
ReliabilityFirst	No	ReliabilityFirst requests clarification on the term ?Interconnected Element.? First, is the term ?facilities? referring to the NERC Glossary of Terms defined term ?Facility?? If so, this term needs to be capitalized. Furthermore, if this is the intent, with a Facility being defined as ?a set of electrical equipment that operates as a single Bulk Electric System Element?, there seems to be no need to add the term ?BES? to the beginning of the definition. a. ReliabilityFirst recommends capitalizing the term ?facility? and b. deleting the term ?BES? from the definition.
Response: Thank you for your comment. a. The drafting team agrees and accepts your suggestion of capitalizing "Facility". b. The drafting team contends the inclusion of BES in the definition is appropriate for emphasis.		
Associated Electric Cooperative,	No	AECI remains unclear as to the intent and effect of PRC-027-1?s definition for

Organization	Yes or No	Question 2 Comment
Inc.		?Interconnected Element? with respect to clause-b, ?the same Registered Entity?? clause. As written, this clause potentially captures all internal BES Elements that electrically joins any internal facilities owned within a Registered Entity that represents multiple functional entity responsibilities. Does clause-b intend to scope additional BES Elements: 1) that electrically join facilities between legally distinct entities within the same Registered Entity (including a JRO) that represents multiple functional entity responsibilities (Distribution Provider, Generation Owner, or Transmission Owner), or 2) that (even within a JRO) electrically join only functionally distinct facilities within the same Registered Entity that represents different functional entity responsibilities such that internally included Elements join: DP-GO, DP-TO, GO-TO, while internally Excluded Elements join: DP-DP, GO-GO, TO-TO?
Response: Thank you for your comment. The intent of part “b” in the definition of Interconnecting Element is to address the situation you cite in item 2.		
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency supports comments submitted by Florida Municipal Power Agency.
Response: Thank you for your comment. See the response to Florida Municipal Power Agency.		
Flathead Electric Cooperative, Inc.	No	It is difficult to support the current definition that relies on the BES Element language from the BES definition process that has not been finalized. In our case, there are elements that would not be in scope for Interconnected Element consideration, but if there is no finalization of the BES definition and this standard moves ahead, the heart of this definition would be in flux. More specificity in what equipment we are really talking about here might be helpful in the absense of a settled definition of a BES element.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. Regardless of how the "BES" is finally defined, the applicability of this standard will not be affected.		
JEA	No	Most of the standard (R1.2, R2.2.1, R3 & R4) should not be applicable to a Registered Entity that represents multiple functional entity where the same system protection group has responsibility for the protection of their entire control area.
Response: Thank you for your comment. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities."		
Madison Gas and Electric Company	No	NSRF?s concern with the proposed definition is related to part B of the definition, on how to prove compliance in case of a vertically- integrated Registered Entity where one department is responsible for performing PSCS and the same Registered Entity is performing multiple functions. Recommend that the measures be updated for both part A and part B or clarity within the RSAW.
Response: Thank you for your comment. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities." The drafting team reviewed the measures and disagrees that they require updating. Measures provide examples of evidence that can be used to demonstrate compliance.		
Southwest Power Pool	No	Our concern with the way the definition is worded relates to how to prove compliance between separate entities as well as entities within a vertically integrated utility. How would a Registered Entity actually show that the proper coordination took place? In some instances it appears that evidence would have to be provided for coordination within the same department of an entity. On the other

Organization	Yes or No	Question 2 Comment
		hand, if separate entities are involved, just what evidence would be required to show adequate coordination? Does this need to be formal documentation indicating all the owners of the interconnecting facility?
Response: Thank you for your comment. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities." Measures provide examples of evidence that can be used to demonstrate compliance.		
Pepco Holdings	No	PHI suggests the definition of Interconnection Element be revised as follows:?Interconnection Element: A BES element that electrically joins facilities a) owned by separate Registered Entities, or b) operated by separate Functional Entities (Distribution Provider, Generation Owner, or Transmission Owner) within the same Registered Entity.? Without this change the existing language could be mis-interpreted as requiring a documented Protection System Coordination Study on each and every internal BES transmission line (transmission line to transmission line coordination) within a Registered Entity?s system, just because the Registered Entity has registered as multiple Functional Entities, and despite the fact that all the lines in question are owned and operated by the same Transmission Owner Functional Entity. The intent of the standard is to address coordination of interconnected elements between separate Registered Entities or between separate functional entities within the same Registered Entity.
Response: Thank you for your comment. Based on stakeholder comments, the drafting team modified the definition to read: Interconnecting Element: A Bulk Electric System (BES) Element that electrically joins Facilities:		

Organization	Yes or No	Question 2 Comment
a) owned by separate Registered Entities, or b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Transmission Owner, Generator Owner, or Distribution Provider). The drafting team intends for this standard to address coordination of Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements, and that require coordination for isolating those faulted Elements - between separate Registered Entities or between separate functional entities within the same Registered Entity.		
Bureau of Reclamation	No	1. Reclamation appreciates the drafting team?s clarification of the definition of Interconnected Element to specify that Interconnected Elements must be ?BES Elements.? However, Reclamation believes that the addition of part b) of the definition is problematic. Reclamation believes that ?Interconnected Elements? covered by the standard should only join facilities owned by separate Registered Entities as specified in part a) of the definition. Reclamation is not clear on how an entity would document internal coordination of Protection System Coordination Studies for the TO and GO arms of the same entity. Reclamation notes that the examples provided by the drafting team in the Application Guideline Diagrams appear to describe only Interconnected Elements at the point of demarcation between separate registered entities. At some Reclamation facilities, the same staff members coordinate TO and GO relay settings, so it is not clear how the studies and concurrence required under R1-R4 would be accomplished. Reclamation believes that PRC-023, PRC-025, and other standards will ensure that TO and GO relay settings are appropriate, and that PRC-027 should only address relay setting coordination where facilities join separate Registered Entities. In addition, the Background section of the standard explains that one purpose of the standard is to address the August 14, 2003 blackout report recommendation on the need to ?address ?the appropriate use of time delays in relays,? by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve

Organization	Yes or No	Question 2 Comment
		coordination. Consistent with this rationale, Reclamation recommends that the drafting team modify the definition of Interconnected Element to read, ?A BES Element that electrically joins facilities owned by separate Registered Entities.? 2. Finally, Reclamation notes that the definition of Elements in the NERC Glossary is, ?Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.? By incorporating the term Element, PRC-027-1 perpetuates the ambiguous definition of Elements by including the term ?such as,? which creates an open-ended list of possible Elements. Reclamation believes it would be helpful for entities to have a better defined list of possible ?Interconnected Elements? so that Entities can ensure compliance.
Response: Thank you for your comment. 1. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities." 2. The drafting team contends the use of the NERC Glossary of Terms "Element" is appropriate within the context of the term "Interconnecting Element". Please reference the figures in the Guidelines and Technical Basis section of the standard for various examples of Interconnecting Elements.		
LG&E and KU Services	No	Section b) of the definition should be deleted. An ?interconnected element? subject to these requirements should not include elements owned/operated by the same registered entity. To minimize the impact of equipment outages under fault conditions, coordination studies are routinely performed by vertically integrated utilities that own and operate facilities that extend from generation plants to distribution pole top transformers. The requirements appear to be intended to insure this same level of coordination is achieved between disparate

Organization	Yes or No	Question 2 Comment
		owner/operators of upstream and downstream facilities. Moreover, as used throughout industry the term interconnected generally refers to electrically contiguous facilities belonging to different operators. After eliminating part b) of the definition, PRC-027 requirements would still apply to vertically integrated registered entities at each point of interconnection with facilities owned/operated by unaffiliated and separately registered entities performing as, e.g., DPs, GO/GOPs, neighboring TOs as appropriate.
Response: Thank you for your comment. The drafting team contends part "b" is necessary because in some vertically integrated utilities, coordination related to different functional entities may not be performed by the same protection group. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities."		
SMUD	No	SMUD believes the Interconnected Element should be defined as those BES elements that electrically join two or more facilities. SMUD disagrees with differentiating ownership as this delineates those requirements based upon ownership causing confusion and an administrative burden for those entities that solely own and coordinate protection components to demonstrate compliance for internal notifications.
Response: Thank you for your comment. The drafting team disagrees with your suggested change to the definition. The drafting team intends for this standard to address coordination of Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements, and that require coordination for isolating those faulted Elements - between separate Registered Entities or between separate functional entities within the same Registered Entity.		
ITC	No	1. The Applicability section 4.2 defines ?facilities? as protection systems with the purpose of detecting BES faults on Interconnected Elements. Therefore, in example Figure 4 the DP does not own ?facilities? and the transmission line or tap are not an

Organization	Yes or No	Question 2 Comment
		Interconnected Element. The definition of Interconnected Element should reflect this fact and Figure 4 should be corrected. If the intention is that Figure 4 should be an Interconnected Element so that R2 still applies, then clarification that Interconnected Elements does not require Applicability section 4.2 defined facilities is required. 2. ITC Holdings engineers perform coordination at Interconnected Elements between ITC Holdings subsidiaries ITCTransmission and METC, both registered TOs. The definition should exclude applications such as this, where the only outcome is increased administrative burden to be auditable with no reliability benefit to BES.
Response: Thank you for your comment. 1. The drafting team revised Figures 3 and 4 in the Guidelines and Technical Basis section of the standard and the associated texts for clarity. 2. The drafting team disagrees with your premise. The drafting team intends for this standard to address coordination of Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements, and that require coordination for isolating those faulted Elements - between separate Registered Entities or between separate functional entities within the same Registered Entity. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities."		
Florida Municipal Power	No	1. The definition poses a problem with the second bullet. It is relatively easy to determine the "boundaries" between separate Registered Entities. It can be difficult to determine the boundaries between where an entity's separate registrations begin and end. Just look at how difficult determining the boundaries of the BES is, and witness the challenges of the GO/TO project where the boundaries between GO and TO are/were not clear. This standard now requires us to also draw the boundary between TO and DP. For example, let's take a step-down transformer to distribution that is connected to a ring bus or breaker-and-a-half scheme. Typically, the high side relays for the

Organization	Yes or No	Question 2 Comment
		transformer will be connected to the current transformers on the breaker bushings within the bus arrangement, which are part of the BES. Those relays are not only there to protect the transformer (not BES), but, also the bus section within the ring or breaker-and-a-half scheme (which is BES). So, are those relays (e.g., differential, directional overcurrent looking into the transformer) owned by the TO or DP registration? 2. It also seems to FMPA that the reliability objective should not be limited to coordinating relays at just the "boundaries"; so, maybe one way to solve the boundary issue is to ignore it and just require a Registered Entity to coordinate its relays that protect the BES. This would expand the scope of the standard even more than the current PRC-001 to the proposed PRC-027, but, it would meet the reliability objective better. Another way to do it is to coordinate all at > 200 kV following PRC-023, and coordinate at the boundaries between entities (not registrations), at all BES.
Response: Thank you for your comment. 1. In the example you cite, if the Distribution Provider has Protection Systems that meet the Applicability; then they are subject to this standard. 2. The drafting team disagrees with both of your suggestions regarding the scope of the standard. The drafting team is not permitted to expand the scope of the SAR for this project. This standard is only applicable to Protection Systems on Interconnecting Elements as stated in the Applicability.		
City of Tacoma	No	There is some concern about the language in part b of the proposed definition of an Interconnected Element. In some cases, a Registered Entity may have one engineering group that is responsible for all Protection Systems, regardless of registered function. Part b of the proposed definition seems to suggest that documented PSCSs, including coordination activities, could be required by proposed PRC-027-1 even if the same engineering group is responsible for all Protection Systems associated with the Interconnected Element. A distinction should be drawn between a Registered Entity in which one engineering group is responsible for

Organization	Yes or No	Question 2 Comment
		Protection Systems associated with its DP, GO, and TO functions, as applicable, and another Registered Entity in which a different engineering group is responsible for Protection Systems associated with its DP vs. GO vs. TO functions, as applicable.
Response: Thank you for your comment. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities."		
Clark Public Utilities	No	There still is some concern regarding coordination within a Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner). This type of Registered Entity is one organization and the standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one entity. The comments below provide specifics of these concerns. In order to address these concerns it is suggested that the words ?separate? and ?same? in this definition be capitalized for reference purposes. The definition should be modified as follows:Interconnected Element: A BES Element that electrically joins facilities owned by:a) Separate Registered Entities, orb) the Same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).
Response: Thank you for your comment. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities." The drafting team sees no benefit in capitalizing the terms "separate" and "same", and declines to make the suggested change.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td>Texas Reliability Entity</td><td>No</td><td>We have concerns with this proposed definition surrounding the current state of the proposed BES definition changes especially in light of the multiple possible exclusions that may be allowed. In ERCOT, there are numerous large private-use-networks (PUNs) with generation behind the fence that could possibly be excluded under the new BES definition, based solely on how much power they export to the grid. If the new definition of the BES grants exclusions to these PUNs, then the PUN as well as the Transmission Owner that connects to the PUN would not be subject to the requirements of PRC-027. In our opinion, this presents a risk to the BES in that there could possibly be protection systems associated with the PUN interconnection that might need to be coordinated to properly respond to faults on the BES or within the PUN. These protection systems should require some level of coordination between the entities involved.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Regardless of how the “BES” is finally defined, the applicability of this standard will not be affected.</td></tr>
<tr><td>Manitoba Hydro</td><td>Yes</td><td>(1) For clarity, consider re-writing the definition as ?A BES Element that electrically joins a Facility owned by:
a) a separate Registered Entity, or
b) the same Registered Entity that is represented by multiple functional entities (Distribution Provider, Generator Owner, or Transmission Owner).?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team disagrees with the suggested change; however, based on stakeholder comments, the definition was modified to read:
Interconnecting Element: A Bulk Electric System (BES) Element that electrically joins Facilities:
a) owned by separate Registered Entities, or
b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Transmission Owner, Generator Owner, or Distribution Provider).</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
Ameren	Yes	(1) The word ?facilities? should be capitalized, since it is included in the NERC Glossary: ? Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)? and ? Element - Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.?
Response: Thank you for your comment. The drafting team agrees and made the suggested change.		
Dominion	Yes	1). The word ?facilities? included in the proposed definition, ?Interconnected Element: A BES Element that electrically joins facilities owned by?? should be capitalized as it is included in NERC?s Glossary of Terms Used in NERC Reliability Standards. 2). Dominion agrees with SERC PCS comment: ?As evident by a note in the rational box for R1 (Page 6 of Redline Version) the drafting team recognizes that vertically integrated entities that have the same personnel performing the review of protection systems for the function of the TO and GO could be unnecessarily burdened if the definition were misconstrued to the point of requiring these personnel to display evidence of comparing studies with themselves. To ensure that this intent is retained in the final version of the standard it is suggested that this note or some derivative be placed somewhere in body of the standard such as the definition of Interconnected Element or under the requirements.?
Response: Thank you for your comment.		

Organization	Yes or No	Question 2 Comment
1. The drafting team agrees and made the suggested change. 2. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities."		
SERC RRO	Yes	As evident by a note in the rational box for R1 (pg. 6) the drafting team recognizes that vertically integrated entities that have the same personnel performing the review of protection systems for the function of the TO and GO could be unnecessarily burdened if the definition were misconstrued to the point of requiring these personnel to display evidence of comparing studies with themselves. To ensure that this intent is retained in the final version of the standard it is suggested that this note or some derivative be placed somewhere in body of the standard such as the definition of Interconnected Element or under the requirements.
Response: Thank you for your comment. The Rationale boxes will be moved but will remain in the final version of the standard; therefore, the drafting team did not insert it elsewhere in the body of the standard.		
DTE Electric	Yes	None
Ingleside Cogeneration LP	Yes	The addition of the modifier ?BES? to describe the applicable Elements is critical in Ingleside?s view. Without it, CEAs may assume that a Fault study is required for an interconnection at any voltage ? an issue highlighted in FERC Order 773 concerning the Definition of the BES.
Response: Thank you for your comment.		
American Electric Power	Yes	The term ?functional entity? is defined in the NERC Glossary of terms and we believe it should be capitalized in this definition.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. The term "functional entity" is not in the NERC Glossary of Terms and should not be capitalized.		
Cooper Compliance Corp	Yes	We would like confirmation that this proposed Standard only requires a study for elements that have been determined to be BES elements. For example, a study would not be required on Elements that connect a radial line serving only load because by definition of BES, there are no BES elements to study.
Response: Thank you for your support. The drafting team agrees with your premise; however, if the radial line is included in the BES and has Protection Systems included in the Applicability of this standard, then the standard would be applicable.		
Kansas City Power and Light	Yes	Yes, as long as the standard only requires documentation in cases where there are neighboring owners that need to agree on protection and control. As an owner of multiple functional entities, we believe that the BES would not benefit by an intra-utility documentation process, not when the required due diligence is already performed within our System Protection Engineering group. Our System Protection Engineering group is already responsible for the coordination of all protection, whether generation, transmission, or distribution.
Response: Thank you for your support. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities."		
ISO RTO Council Standards Review Committee	Yes	
Northeast Power Coordinating	Yes	

Organization	Yes or No	Question 2 Comment
Council		
Duke Energy	Yes	
FirstEnergy Corp	Yes	
Essential Power, LLC	Yes	
PacifiCorp	Yes	
Electric Reliability Compliance	Yes	
Southern Company	Yes	
Exelon and its Affiliates	Yes	
Independent Electricity System Operator	Yes	
Public Service Enterprise Group	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Tri-State G &T	Yes	
Wisconsin Electric Power Company	Yes	
NextEra Energy	Yes	

Organization	Yes or No	Question 2 Comment
Xcel Energy	Yes	
California ISO		See associated SRC Comments
Response: Thank you for your comment. Please refer to the responses for SRC comments.		

3. **In Requirement R1, the drafting team modified the time frame to allow entities 60 months to have a documented Protection System Coordination Study (PSCS) completed for each Interconnected Element if no PSCS exists. Note, the drafting team has allowed inclusion of all previously performed PSCS whose summary of results include, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. Do you agree with this revised time frame? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Approximately 70% of commenters agreed with the revised time frame of 60 months to produce a documented Protection System Coordination Study (PSCS) for each Interconnected Element, if none exists. A few commenters thought that 60 months was either too long or too short. The drafting explained that the change to 60 months was made based on the reasonable arguments presented by the majority of stakeholders.

One commenter suggested there were too many time frames in general in the requirements. The drafting team responded that the specific time frames are appropriate and relevant for the reliability-related tasks in each of the requirements.

There were numerous comments unrelated to this question that were addressed but are not included in this summary.

Organization	Yes or No	Question 3 Comment
ATCO Electric	No	- R1 referring to other requirements with different timelines is very confusing to understand and execute. - R1 (and PRC-027-1 draft 3 in general) also has too many timelines: 90 calendar days, 60 calendar months, 12 calendar months, "agreed upon timefram

Response: Thank you for your comment.

The drafting team contends the specific time frames are appropriate and relevant for the reliability-related tasks in each of the requirements. The process flow chart is included in the Guidelines and Technical Basis section of the standard shows the relationship between the requirements.

Organization	Yes or No	Question 3 Comment
ReliabilityFirst	No	a. ReliabilityFirst believes the shift from 48 calendar months to 60 calendar months is an excessive amount of time to allow an entity to perform a Protection System Coordination Study (PSCS). With the effective date of the standard being 12 months beyond the date that it is approved by applicable regulatory authorities, this is essentially giving entities over six years to perform their initial study, for equipment that previously had no study performed. Furthermore, from a reliability perspective, this coordination is most likely already occurring in some capacity, when the interconnection is made, and entities should not require this excessive timeframe to perform the study (i.e., as quoted from the SDT: ??there is no evidence of widespread miscoordination of Protection Systems associated with Interconnected Elements??). ReliabilityFirst recommends a 24 calendar month implementation timeframe to limit any potential reliability issues as a result of shortcomings in the existing set of Standards.
Response: Thank you for your comment. The time frame was revised to 60 months based on the reasonable arguments presented by the majority of stakeholders.		
Madison Gas and Electric Company	No	As currently written, each TO, GO and DP are required to perform a PSCS. This will lead to multiple efforts by each entity. Recommend that GO and DP be removed from this Requirement. Since the TO has access to the hierarchy of systems (Interconnected Elements) they are positioned to request current protection system settings from the GO and DP and then perform a PSCS. They can then request adjustments by the GO and DP in order to assure a more secure system.
Response: Thank you for your comment. The drafting team contends that it is the Protection System owner's responsibility to ensure that a Protection System Coordination Study is performed.		
Bonneville Power Administration	No	BPA believes that the requirement to provide a protection system study for each interconnected element is onerous, and as a result, any amount of time is too short. While beneficial to periodically perform fault studies and review protection system

Organization	Yes or No	Question 3 Comment
		coordination, the creation of a NERC standard to require reviews for Interconnected Elements on a rigid time frame is likely to be counterproductive for the following reasons: a. There is nothing unique about the Protection Systems for Interconnected Elements compared to other Protection Systems that warrants this special treatment. If this standard is deemed necessary, the only logical consequence is that similar standards must be created for all protection systems. Trying to coordinate Protection Systems to comply with numerous standards will limit flexibility. Diverting resources from addressing Protection System problems to completing compliance documentation makes the system less reliable, not more. b. This standard provides no quality benefit to the Protection System Coordination process. It only increases the documentation burden, which is just as likely to decrease the quality of the review as it is to improve it. c. There are an enormous number of things that entities do to keep the BES reliable. If NERC wishes to regulate and enforce all of these things, it will come at an enormous cost to consumers of electric power. Cost increases are already being experienced due to the present standards. Since there has been no widespread problem with Protection System coordination between entities, this particular issue should not be the subject of a standard. d. Any specified time frame for a Protection System Coordination review will be too long for some situations and too short for others. The Protection System Engineers within the entities are in the best position to determine an appropriate review interval for each element.
Response: Thank you for your comment. a, b, c, d. The standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.		
Florida Municipal Power	No	1. Five (5) years seems way too long for an initial coordination study. We

Organization	Yes or No	Question 3 Comment
		should pick a period of time that both industry and FERC will likely approve, maybe something like two (2) years. 2. Other comments on R1:FMPA's interpretation of the Applicability combined with the standard is that remote back-up protection is included as it was "installed for the purpose of detecting Faults on Interconnected Elements". This becomes ambiguous for directional, inverse time ground current protection whose reach can vary with ground current, or with such relays and zone distance relays with changes in system configuration. FMPA's interpretation is that the Applicability is to the maximum reach of such relays; is that the intent of the SDT? 3. Bullet 1.2 is ambiguous in its use of the term "owner"; especially in combination with the definition of Interconnected Element that makes the distinction between different registered functions within the same entity. Is the owner the entity, or the registered function? We assume the "owner" is the entity; is that the intent of the SDT?

Response: Thank you for your comment.

1. The time frame was revised to 60 months based on the reasonable arguments presented by the majority of stakeholders.
2. The standard is applicable to: Protection Systems: a) installed for the purpose of detecting Faults on Interconnecting Elements, and; b) that require coordination for isolating those faulted Elements.
3. The "owner" is the functional entity that owns the Protection System.

Organization	Yes or No	Question 3 Comment
Ingleside Cogeneration LP	No	ICLP mostly agrees with rationale for R1 that states ?The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame <than 60 months>.? We would take that one step further and argue that far more critical coordination occurs in UVLS, UFLS, SPS, and distance relay schemes ? and is already covered in other NERC standards. Fault analyses are comparatively basic, and do not require a re-evaluation unless a material change is made in the local grid. This means that a

Organization	Yes or No	Question 3 Comment
		Generator Owner should be able to make a simple confirmation that nothing has changed since the previous time a Fault study was performed ? usually during commissioning or a major reconfiguration. If the TO wants a full Fault evaluation due to a change in the local transmission system, they are free to do so under R1.1.2. Requiring every GO to produce the results of a study that took place years in the past serves no reliability purpose.
Response: Thank you for your comment. The drafting team contends there is a reliability benefit in ensuring that all existing Protection Systems on Interconnecting Elements have been reviewed; and that it is the owner's responsibility to ensure a study has been performed. Requirement R1, Part 1.2 describes the minimum that a summary of the results of a Protection System Coordination Study performed pursuant to Requirement R1, Part 1.1 must include. The Generator Operator must provide the summary results to the other owner(s) within 90 days to satisfy the intent of the requirement.		
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency supports comments submitted by Florida Municipal Power Agency.
Response: Thank you for your comment. See the response to Florida Municipal Power Agency.		
Wisconsin Electric Power Company	No	Requirement 3.3 needs to be revised to allow an entity the flexibility to make emergency changes to protection systems or settings that are necessary to correct a reliability problem. The current draft allows such changes only when a failure occurs.
Response: Thank you for your comment. Requirement R3 mandates the provision of information to other owners after changes to Protection Systems associated with the Interconnecting Element have occurred. The requirement is not precluding any maintenance work. Requirement R3, Part 3.3 specifies that the entity must provide information regarding whatever maintenance was done within 30 calendar days of completing the maintenance.		

Organization	Yes or No	Question 3 Comment
SMUD	No	The revised time frame of 60 months is agreeable, however, requirement 1.2 should not be applicable to any Interconnection Element owners that are one of the same Registered Entity that represents multiple functional entity responsibilities. There are several Registered Entities that have only one person or department within a utility that is responsible for protection system coordination for all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the organization that developed the Protection System Coordination Study to provide a copy to ?other owners?. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner.
Response: Thank you for your comment. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: “In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities.”		
Clark Public Utilities	No	1. The revised time frame of 60 months is agreeable, however, requirement 1.2 should not be applicable to any Interconnection Element owners that are part of the ?same Registered Entity that represents multiple functional entity responsibilities.? Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the organization that developed the Protection System Coordination Study to provide a copy to ?other owners?. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. 2. Since the definition of Interconnection Elements incorporates the concept of

Organization	Yes or No	Question 3 Comment
		?Separate Registered Entities and ?Same Registered Entities? it is suggested that the wording be modified to incorporate theses terms as follows:R1.2 Within 90 calendar days after the completion of each PSCS, provide to the other Separate Registered Entities that are owner(s) of the Protection System(s) associated with the Interconnected Element(s), a summary of the results of each PSCS performed pursuant to Requirement R1, Part 1.1, (including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed).
Response: Thank you for your comment. 1. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities." 2. The drafting team disagrees with your suggested changes to Requirement R1, Part 1.2.		
LG&E and KU Services	No	There is no basis for performing studies every 60-months. Such studies should be performed when necessary based on predetermined criteria set forth in the standard. There is no evidence of wide spread miscoordination of Protection Systems associated with Interconnected Elements. In fact, none of the recent blackouts resulted from miscoordination of protective settings.
Response: Thank you for your comment. Requirement R1 does not mandate that a PSCS be performed every 60 months. The requirement states the conditions that require a PSCS be performed.		
Exelon and its Affiliates	No	We do not believe that a mandatory PSCS needs to be completed for each interconnected element as stated in Requirement 1. We believe that the design of the Protection System for an interconnected element must first be considered before requiring a PSCS. In cases where high speed protection schemes are redundant, the reliance on time-delayed backup elements would require at least 2

Organization	Yes or No	Question 3 Comment
		protection system element contingencies. We propose that redundancy should consist of the use of two separate relays and auxiliary relays as per the redundancy test required in the NERC board-approved TPL-001-2 standard. If failure of a single relay or auxiliary relay results in reliance on time delayed back-up protection, we agree that a PSCS should be required, and consequently would agree to the 60 month time frame.
Response: Thank you for your comment. The application of redundant Protection Systems does not preclude the necessity of ensuring that your Protection Systems are coordinated.		
Northeast Power Coordinating Council	Yes	60 months is an adequate and appropriate period which balances the interest of reliability with the economics related to engineering costs.
Response: Thank you for your support.		
Duke Energy	Yes	Duke Energy agrees with the changes made by the SDT to extend the period to 60 months.
Response: Thank you for your support.		
DTE Electric	Yes	None
Response: Thank you for your support.		
ISO RTO Council Standards Review Committee	Yes	SRC chooses not to respond to this question, please disregard the response as it was selected in error and could not be deleted.
Pepco Holdings	Yes	
FirstEnergy Corp	Yes	
Dominion	Yes	

Organization	Yes or No	Question 3 Comment
Essential Power, LLC	Yes	
Associated Electric Cooperative, Inc.	Yes	
Southwest Power Pool	Yes	
SERC RRO	Yes	
JEA	Yes	
City of Tacoma	Yes	
PacifiCorp	Yes	
Electric Reliability Compliance	Yes	
PJM Interconnection	Yes	
Bureau of Reclamation	Yes	
Southern Company	Yes	
Dynegy	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	
Texas Reliability Entity	Yes	

Organization	Yes or No	Question 3 Comment
American Electric Power	Yes	
ITC	Yes	
Public Service Enterprise Group	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Tri-State G &T	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Ameren	Yes	
Kansas City Power and Light	Yes	
NextEra Energy	Yes	
Xcel Energy	Yes	
California ISO		See associated SRC Comments
Response: Thank you for your comment. Please refer to the responses for SRC comments.		

4. **In Requirement R2, the drafting team modified the time frame to 60 months for either conducting a Fault current review or provide a technical justification as to why a Fault current review is not necessary. Do you agree with this revision to Requirement R2? If not, please provide specific suggestions for improvement in the comment area.**

Summary Consideration:

No specific changes to the timeframe in Requirement R2 were made based on comments. , however, overall discussion within the drafting team related to comments received did result in the removal of the provision that the Transmission Owner could provide a technical justification for not conducting the 60 month Fault current review specified in Requirement R2.

A few commenters suggested that a provision should be included to require Transmission Owners to provide system fault data to Distribution Providers and Generator Owners on a continuous basis. The drafting team does not agree that more frequent exchanges are required because each interconnected owner has the ability to request information at any time (Requirement R3 Part 3.2).

A few commenters continue to suggest that Generator Owners (GO) should be excluded from performing a Protection System Coordination Study (PSCS) after being notified by the Transmission Owner of a 10% or greater change in Fault current at an interconnecting bus. The drafting team responded that a GO could provide a technical justification explaining why changes in bus Fault current do not affect its coordination rather than performing a Protection System Coordination Study (PSCS), and that a previous technical justification could be reused provided it is still valid.

Several commenters suggested that Requirement R2 should not apply to Registered Entities that represent multiple functional entity responsibilities. The drafting team responded that for the case where one registered entity representing multiple functional entities with the same protection group performing all the coordination, the drafting team included the following note: “In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities.

Organization	Yes or No	Question 4 Comment
ATCO Electric	No	- R2 referring to other requirements with different timelines is very confusing to

Organization	Yes or No	Question 4 Comment
		understand and execute. - R2 (and PRC-027-1 draft 3 in general) also has too many timelines: 90 calendar days, 60 calendar months, 12 calendar months, "agreed upon timefram
Response: Thank you for your comment. A process flowchart is included in the Guidelines and Technical Basis section of the standard to show the relationship between the requirements. The drafting team contends the specific time frames are appropriate and relevant for the reliability-related tasks in each of the requirements.		
Ingleside Cogeneration LP	No	Although ICLP is not a Transmission Owner, we will be impacted if the TO?s assessment shows a material change in Fault current has occurred in an interconnecting element. We believe our TO has every economic and reliability incentive to contact us if a modification threatens the transmission network. It should be sufficient that the TO show that a coordinated assessment takes place when an appropriate trigger condition occurs.
Response: Thank you for your comment. The intent of Requirement R2 is for the Transmission Owner to inform the other owner(s) of a change in Fault currents of 10% or more. The drafting team contends a 10% change in Fault current is an appropriate trigger. Note that the standard (Requirement R1, Part 1.1.2) allows an entity (a Generator Owner in your case) to provide a technical justification explaining why changes in bus Fault current do not affect its coordination rather than performing a Protection System Coordination Study (PSCS). A Generator Owner is allowed to reuse its previous technical justification provided it is still valid to justify why a new PSCS is not required.		
DTE Electric	No	Comments: Since the main purpose of this standard is to assure coordination of BES Interconnected Elements, there should be a provision included to require TOs to provide system fault data to DPs and GOs on a continuous basis so that coordination is performed on BES as well as non-BES elements using accurate data. If complete system fault study files are provided regularly (bi-annually?), projects can be completed using the latest data and not subject to re-evaluation when an update is provided by the TO every 60 months. It is critical that fault study data file compatibility exists between the short circuit programs of the different entities.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. The drafting team does not agree that more frequent exchanges need be mandated through a requirement because each interconnected owner has the ability to request information at any time as part of Requirement R3 Part 3.2. This standard does not prevent an owner from performing more frequent reviews.		
Bonneville Power Administration	No	Please see comments for Question 3.
Response: Thank you for your comment. Please see the response for Question #3.		
SMUD	No	Please see our comments in Question #3; The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner.
Response: Thank you for your comment. Please see the response for Question #3.		
LG&E and KU Services	No	See response to question 3 above.
Response: Thank you for your comment. Please see the response for Question #3.		
Clark Public Utilities	No	1. The revised time frame of 60 months is agreeable, however, requirement 2.2.1 should not be applicable to any Interconnection Element owners that are part of the ?same Registered Entity that represents multiple functional entity responsibilities.? Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the organization that developed the updated Fault current study to provide the updated Fault current values (Iscs) to ?each owner? of the Protection System

Organization	Yes or No	Question 4 Comment
		associated with the Interconnected Element. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. 2. Since the definition of Interconnection Elements incorporates the concept of ?Separate Registered Entities and ?Same Registered Entities? it is suggested that the wording be modified to incorporate theses terms as follows:R2.2.1 Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (Iscs) to each Separate Registered Entity that is an owner of the Protection System associated with the Interconnected Element.
Response: Thank you for your comment. 1. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities." 2. The drafting team disagrees with your suggested changes to Requirement R1, Part 1.2.		
Exelon and its Affiliates	No	This requirement unnecessary burden on the Generation Owner. The fault current seen by Generator Owner?s protective devices depend on the Generation Owners equipment (e.g., the main generator and transformers). So unless those are replaced there should be no requirement on the Generator Owner to review the protection coordination study due to change in fault current at the interconnecting bus which will be due to grid changes. The Transmission Owner will be reviewing those changes and will be coordinating if needed with the Generator Owner. Therefore these requirements should not be applicable to Generation Owner. [Requirement R1 1.1.2 and Requirement R 4 4.1 should also not be applicable to Generator Owner for same reason].Need to identify which elements of Generator Owner?s protection system are included in this Standard and provide specific criteria

Organization	Yes or No	Question 4 Comment
		for showing coordination with TOs protective devices.
Response: Thank you for your comment. Requirement R2 is only applicable to Transmission Owners. Note that the standard (Requirement R1, Part 1.1.2) allows an entity (a Generator Owner in your case) to provide a technical justification explaining why changes in bus Fault current do not affect its coordination rather than performing a Protection System Coordination Study (PSCS). A Generator Owner is allowed to reuse its previous technical justification provided it is still valid to justify why a new PSCS is not required.		
Public Service Enterprise Group	No	We agree with that the 60 months is adequate; however, we disagree that a technical justification should be required for relays and schemes that are unaffected by the level of Fault current. See our proposed language changes in 8.a below.
Response: Thank you for your comment. If you meet the qualifications regarding the Applicability section of the standard: e.g., you are one of the owners listed in the Functional Entities section 4.1 and you own Facilities as described in the Facilities section 4.2 of the standard, the standard is applicable to you. The drafting team contends an initial technical justification is required to demonstrate that the Protection Systems are not impacted by changes in Fault current. A Generator Owner is allowed to reuse its previous technical justification provided it is still valid to justify why a new PSCS is not required (as in Requirement R1, Part 1.1.2).		
Ameren	Yes	(1) The "maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus" could either be the total Fault current at that bus, or the Fault current flowing through the Interconnected Element. Our reading of R2, Part 2.2 "used in the most recent PSCS" is that it depends on what the entity used in their study.
Response: Thank you for your comment. The drafting team intends for the "…maximum available Fault current values…at its interconnecting bus(s)…" to be determined.		
Northeast Power Coordinating Council	Yes	60 months is an adequate and appropriate period which balances the interest of reliability with the economics related to engineering costs.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your support.		
Duke Energy	Yes	Duke Energy agrees with the changes made by the SDT to extend the period to 60 months.
Response: Thank you for your support.		
ISO RTO Council Standards Review Committee	Yes	SRC chooses not to respond to this question, please disregard the response as it was selected in error and could not be deleted.
Florida Municipal Power	Yes	
Pepco Holdings	Yes	
FirstEnergy Corp	Yes	
Dominion	Yes	
Essential Power, LLC	Yes	
Madison Gas and Electric Company	Yes	
Associated Electric Cooperative, Inc.	Yes	
Southwest Power Pool	Yes	
SERC RRO	Yes	
JEA	Yes	

Organization	Yes or No	Question 4 Comment
City of Tacoma	Yes	
PacifiCorp	Yes	
Electric Reliability Compliance	Yes	
PJM Interconnection	Yes	
Bureau of Reclamation	Yes	
Southern Company	Yes	
Dynegy	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	
Texas Reliability Entity	Yes	
American Electric Power	Yes	
ITC	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Tri-State G &T	Yes	
Flathead Electric Cooperative,	Yes	

Organization	Yes or No	Question 4 Comment
Inc.		
Wisconsin Electric Power Company	Yes	
NextEra Energy	Yes	
Xcel Energy	Yes	
Illinois Municipal Electric Agency	Yes	
California ISO		See associated SRC Comments
Response: Thank you for your comment. Please refer to the responses for SRC comments.		
Kansas City Power and Light		The modification to a longer time frame is acceptable. However, we do not agree that there is adequate justification for requiring a fault current review every five years. Relay settings that are valid today will remain valid until changes are made at our end of an interconnected element or when another Registered Entity notifies us of change. A technical justification that is valid today will remain valid until changes are made to the BES within our system or a neighboring owner?s system.
Response: Thank you for your comment. The drafting team contends that a Fault current review and notification should remain in the standard. Upon notification, the other owner has the option to review and use a previously developed technical justification provided it is still valid to justify why a new PSCS is not required (Requirement R1, Part 1.1.2).		

5. **In Requirement R4, the drafting team has clarified the expectation of what a response to a review of the summary results of a Protection System Coordination Study should include. The options are as follows: • Accepting the results, or • Rejecting the results and suggesting modifications to resolve any identified coordination issues. Do you agree with this revision to Requirement R4? If not, please provide specific suggestions for improvement in the comment area.**

Summary Consideration:

Approximately 70% of the respondents supported the changes made to Requirement R4, but expressed a desire for additional clarity. However, a few commenters continue to suggest that mutual agreement on Protection System settings between owners will sometimes not be achieved and have compliance concerns associated this fact. Consequently, the drafting team separated Requirement R4 into Requirements R4 and R5. The modified Requirement R4 provides a variety of alternative responses for replying to the other owners after receiving a Protection System Coordination Study (PSCS), or a summary of the results of a PSCS, or a technical justification. The drafting team replaced the language that specified either "accepting" or "rejecting" the summary of the results of a PSCS with confirming that the summary of results or the technical justification were reviewed and whether or not any identified coordination issues were noted. Requirement R4 retains the "90 calendar days" or "agreed-upon schedule" time frames for performing the reviews. The new Requirement R5 mandates that any identified coordination issues be addressed prior to the implementation of any changes or additions to the Protection System(s) associated with the Interconnecting Element.

A few commenters had concerns of possible conflicts between the draft standard and contractual rights associated with existing terms and conditions of generator interconnection agreements. The drafting team responded that they agree that contractual rights must be adhered to, including notice and approval rights, and they do not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the Generator Owner to ensure the Protection Systems covered by this standard are properly coordinated. The drafting team contends that the standard as drafted does not preclude those contracts, but does address instances where a contract may not address modifications. The phrase "according to an agreed upon schedule" in Requirement R4 provides an avenue to follow the terms of the contract.

Two commenters were concerned that a coordination solution between the owners (Transmission Owner(s), Generator Owner(s) and Distribution Provider(s)) could potentially result in unintended consequences for the Transmission Operator(s) (TOPs) so they suggested a notification requirement for the TOP. The drafting team contends the coordination and cooperation among entities as codified in the TOP group of Reliability Standards address notifications of situations potentially posing risk to the reliability of the BES.

A commenter was concerned about the ability to reach agreement when critical replacements are made during unit outages. The response indicated that the drafting team contends the exchange of Protection System information is critical to the reliability of the BES; therefore, the details of any planned changes need to follow the Requirement 3 criteria. Requirement R3, Part 3.3 requires notifications of emergency replacements such as critical changes made during generation outages within 30 calendar days of making the change. Note that the requirement allows agreed upon time frames which could be significantly shorter than the 30 days noted in the standard.

Organization	Yes or No	Question 5 Comment
Nebraska Public Power District	No	In theory I understand the drafting team stating: "The drafting team believes that any conflict resolution should be handled through normal business practices. The old Measure M9 (new Measure M10) has been modified as follows: Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that, prior to implementation of any proposed Protection System(s) changes, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted. The drafting team believes the requestor cannot be held accountable when the other party does not respond". However, I don?t believe that we can predict or project how an audit or enforcement team will apply or misapply this requirement which is cause for concern. There are utilities that will respond but may not respond in a timely manner. This puts all entities unfairly under scrutiny. Perhaps some form of clarification could be added to the application guidelines or another location for example.
Response: Thank you for your comment. The goal of the drafting team is to write clear, concise requirements that leave no room for interpretation by anyone including auditors. In this vein, the drafting team split Requirement R4 into two separate requirements in an effort to improve clarity. The entity not responding in a timely manner pursuant to Requirement R4 would be in violation.		
LG&E and KU Services	No	90-days is not in all cases the appropriate time period to review such results. The terms and conditions for generator interconnections are regulated by FERC or state PUCs. The proposed reliability standard should clearly state that responsible entities

Organization	Yes or No	Question 5 Comment
		are not obligated to take any actions that are inconsistent with the rights of the parties under any interconnection or similar agreements. Such agreements typically address the procedures for making modifications to a party?s facilities that may affect the other party and the required notice and approval rights. The standard should not seek to impose any requirements that are inconsistent with these contractual rights. R4.1 speaks of sharing only, ?summary results,? but the Application Guidelines on p.24 lists as examples ?power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings.? We recommend that the above list be preceded with the words ?summaries of.?
Response: Thank you for your comment. The drafting team agrees that contractual rights must be adhered to, including notice and approval rights. The drafting team contends that the standard as written does not preclude those contracts, but instead address instances where a contract may not address modifications. The phrase “according to an agreed upon schedule” in Requirement R4 provides an avenue to follow the terms of the contract. The drafting team agrees that a “summary” of the PSCS is appropriate. The Guidelines and Technical Basis section of the standard includes a broader listing of documentation that could be provided but may not lend itself to a “summary”. This information should be conveyed as convenient and agreed upon by both the sender and the recipient.		
Flathead Electric Cooperative, Inc.	No	Although well-intended, this seems like a difficult thing to document for audit if there are legitimate back and forth over a long period of time.
Response: Thank you for your comment. As you suggest, there may be instances where substantial back and forth comments could occur; in those cases the parties would retain the correspondence demonstrating that a response acknowledging that “coordination was achieved” was received.		
Florida Municipal Power	No	Bullet 1.2 is ambiguous in its use of the term ?owner?; especially in combination with the definition of Interconnected Element that makes the distinction between different registered functions within the same entity. Is the owner the entity, or the registered function? We assume the ?owner? is the entity; is that the intent of the SDT?

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The "owner" is the functional entity that owns the Protection System.		
Pepco Holdings	No	PHI finds that the revised wording in Section R4 does little to address the root problem associated with mandating mutual agreement. PHI suggests Requirement R4 be removed entirely or extensively re-written to address the concerns outlined below: Requirement R4 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What if agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R4.2 until agreement is reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? This is the

Organization	Yes or No	Question 5 Comment
		problem with mandating that an agreement between two parties be reached. It is further compounded by requiring that an agreement be reached within a set timeframe. It is unreasonable and unfair to hold one party non-compliant due to the failure of another party to reach agreement. Furthermore, in the example provided above, it is a detriment to reliability to delay implementation of the setting change on breaker D just because mutual agreement could not be reached. It is important to ensure that information on new, or modified, Protection Systems are shared between parties, so that each party may assess the impact of the change and ensure their Protection Systems are properly set and coordinated. The emphasis should be on sharing of information (such as relay setting changes) and not the details of performing the ?Protection System Study? and all the associated approval schedules. As such, it may be reasonable to have a Reliability Standard to ensure setting information has been exchanged (which was the original intent of the PRC-001-1 standard). But it should be left at that. Mandating mutual agreement with compliance implications, without providing a clear division of responsibilities and assignment of who will be held non-compliant if agreement cannot be reached is unfair to either party.
Response: Thank you for your comment. The drafting team acknowledges that entities may have differing protection philosophies. Based on yours and other stakeholder comments, the drafting team separated Requirement R4 into two Requirements, R4 and R5. The new Requirement R5 states that any identified coordination issues must be addressed prior to the implementation of any changes or additions to the Protection System(s) associated with the Interconnecting Element. The drafting team contends that any conflict resolution should be handled through normal business practices.		
Wisconsin Electric Power Company	No	R4 needs revision to better accomodate the entire range of diversities in TO-GO interconnections, especially when agreement cannot be reached between entities, or when agreement cannot be reached in a timeframe required to make critical changes during generating unit outages. R4 also neeeds to include flexibility when the GO is not a vertically integrated utility, and does not have in-house protection engineering resources to respond in the required timeframe. It is unjust to put

Organization	Yes or No	Question 5 Comment
		compliance risk on an entity due to the failure of another entity to reach agreement on settings. In some cases the best that can be expected is for two parties to exchange protection system information and live with a compromise in coordination that allows both to best protect their assets. This may be especially true when generating assets are at stake, and insurance considerations require sensitive protection that may not allow complete coordination.
Response: Thank you for your comment. The drafting team acknowledges that entities may have differing protection philosophies. The drafting team contends the exchange of Protection System information is critical to the reliability of the BES; therefore, the details of any planned changes need to follow the Requirement 3 criteria. In the case you cite of critical changes made during generation outages, Requirement R3, Part 3.3 allows notifications of emergency replacements be made. Note that the requirement allows agreed upon time frames which could be significantly shorter than the 30 days noted in the standard. Based on yours and other stakeholder comments, the drafting team separated Requirement R4 into two Requirements, R4 and R5.		
Northeast Power Coordinating Council	No	R4 requires all affected parties agree to a solution. However, the applicable Functional Entities that PRC-027 impacts are limited only to the TO, GO and DP. When designing a protection system scheme to clear faults, a satisfactory solution in the perspective of a TO, GO and DP may have unintended consequences for the Transmission Operator. For example, what if the solution is to leave what in normal operation is a significantly loaded transmission line in a potentially open terminal configuration by leaving a ring bus configuration open after clearing a fault? How can the TO, GO and DP ensure their agreed upon solution is manageable for the Transmission Operator? There should be a notification requirement to the TOP.
Response: Thank you for your comment. The situation you describe is not a satisfactory solution and would not be in keeping with "good utility practice." The drafting team contends the coordination and cooperation among entities as codified in the TOP group of Reliability Standards address notifications of situations potentially posing risk to the reliability of the BES.		
ISO RTO Council Standards	No	R4 requires all affected parties to agree to a solution. However the applicable

Organization	Yes or No	Question 5 Comment
Review Committee		Functional Entities that PRC-027 impacts are limited only to the TO, GO and DP. When designing a protection system scheme to clear faults, a satisfactory solution in the prospective of a TO, GO and DP may have unintended consequences for the Transmission Operator. For example, what if the solution is to leave a significantly loaded transmission line in a potentially single end situation by leaving a ring bus configuration open after clearing a fault? How can the TO, GO and DP ensure their agreed upon solution is manageable for the Transmission Operator? Should there be a notification requirement to the TOP?
Response: Thank you for your comment. The situation you describe is not a satisfactory solution and would not be in keeping with “good utility practice.” The drafting team contends the coordination and cooperation among entities as codified in the TOP group of Reliability Standards address notifications of situations potentially posing risk to the reliability of the BES.		
Essential Power, LLC	No	R4.2 can hold an entity hostage (and possibly non-compliant) if the other Interconnected Element owner does not/will not accept the proposed changes. This requirement is extremely objectionable for entities in deregulated markets, since the ?firewall? separating the regulated and deregulated sides of the business would ordinarily prevent the GO from seeing TO critical infrastructure information. R4.1 speaks of sharing only, ?summary results,? but the Application Guidelines calls on p.24 for transmittal of, ?power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings.? R4.2 also raises concerns for the situation in which a TO connects to GOs within the same corporate umbrella as well as to GOs that are part of completely separate corporate entities. The TO is legally required to treat all GOs equally, and we would certainly expect this to continue to be the case if PRC-027 is enacted, but suspicions could arise whenever expansion plans of a TO are impeded or overtly vetoed via PRC-027 ?reject? decisions by an other-corporate-entity GO and vice-versa. Proposed changes to Interconnection Service Agreements are handled under market rules, and NERC standards should not contain features that might create opportunity for infringing-

Organization	Yes or No	Question 5 Comment
		on or bypassing these rules.
Response: Thank you for your comment. The drafting team acknowledges that entities may have differing protection philosophies. The drafting team contends the exchange of Protection System information is critical to the reliability of the BES. Based on yours and other stakeholder comments, the drafting team separated Requirement R4 into two Requirements, R4 and R5. The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the Generator Owner to ensure the Protection Systems covered by this standard are properly coordinated. The drafting team agrees that a "summary" of the PSCS is appropriate. The Guidelines and Technical Basis section of the standard includes a broader listing of documentation that could be provided but may not lend itself to a "summary". This information should be conveyed as convenient and agreed upon by both the sender and the recipient. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities." The drafting team agrees that contractual rights must be adhered to, including notice and approval rights. The drafting team contends that the standard as written does not preclude those contracts, but instead address instances where a contract may not address modifications. The phrase "according to an agreed upon schedule" in Requirement R4 provides an avenue to follow the terms of the contract.		
Bureau of Reclamation	No	Reclamation agrees with this comment but suggests rephrasing R4 to encourage collaboration among registered entities. Reclamation suggests that R4.1 should read ?Within 90 calendar days after receipt or according to an agreed upon schedule, review the summary results of a PSCS (per Requirement R1, R1.2) and respond to the other owner(s) by accepting the results or suggesting modifications to resolve any identified coordination.? Reclamation does not believe that entities should submit formal rejections of PSCSs merely to satisfy the standard. Reclamation suggests that the phrasing above would better encourage collaborative relay setting coordination.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The drafting team acknowledges that entities may have differing protection philosophies. The drafting team contends the exchange of Protection System information is critical to the reliability of the BES. Based on yours and other stakeholder comments, the drafting team separated Requirement R4 into two Requirements, R4 and R5.		
Bonneville Power Administration	No	The requirement does not describe what further actions are required or what time limits apply if the suggested modifications are not acceptable to the originating entity.
Response: Thank you for your comment. The drafting team acknowledges that entities may have differing protection philosophies. The drafting team contends the exchange of Protection System information is critical to the reliability of the BES. The drafting team contends that any conflict resolution should be handled through normal business practices.		
Clark Public Utilities	No	The response options are agreeable, however, requirement 4 (and any sub-requirements) should not be applicable to any Interconnection Element owners that are part of the ?same Registered Entity that represents multiple functional entity responsibilities.? Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the same organization that developed the Protection System Coordination Study to provide a document accepting it or rejecting it. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. Since the definition of Interconnection Elements incorporates the concept of ?Separate Registered Entities and ?Same Registered Entities? it is suggested that the wording be modified to incorporate theses terms as follows:R4. Each Transmission Owner, Generator Owner, and Distribution Provider that is a Separate Registered Entity and each Same Registered Entity (on behalf of its multiple functional entity responsibilities) shall: [Violation

Organization	Yes or No	Question 5 Comment
		Risk Factor: Medium] [Time Horizon: Operations Planning]4.1. Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a PSCS (per Requirement R1, Part 1.2) and respond to the Registered Entity providing the PSCS:? Accepting the results, or? Rejecting the results and suggesting modifications to resolve any identified coordination issues.4.2. Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other Separate Registered Entities that are owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.
Response: Thank you for your comment. For the case where one registered entity represents multiple functional entities and the same protection group performs all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities."		
Southwest Power Pool	No	The way the requirement is currently worded, the sending entity could conceivably be found non-compliant if an entity receiving the results does not respond within 90 days. We would suggest incorporating language to clarify that the receiving entity has the obligation to respond within 90 days. This could be accomplished by inserting ?each recipient of the results shall? in the requirement. The requirement would then read ?Within 90 calendar days after receipt, or according to an agreed upon schedule, each recipient of the results shall review the summary results of a PSCS??
Response: Thank you for your comment. The goal of the drafting team is to write clear, concise requirements that leave no room for interpretation by anyone including auditors. In this vein, the drafting team split Requirement R4 into two separate requirements in an effort to improve clarity. The entity not responding in a timely manner pursuant to Requirement R4 would be in violation.		

Organization	Yes or No	Question 5 Comment
DTE Electric	Yes	None
City of Tacoma	Yes	Should the Flowchart be updated to reflect the course of action if an entity rejects the results and suggests modifications to resolve any identified coordination issues?
Response: Thank you for your support. The drafting team revised the flow chart to be consistent with the revised requirements.		
FirstEnergy Corp	Yes	We agree with Part 4.1 of Requirement 4, but we have comments regarding Part 4.2 and have stated below in Question 8.
Response: Thank you for your support.		
Duke Energy	Yes	
Dominion	Yes	
Madison Gas and Electric Company	Yes	
Associated Electric Cooperative, Inc.	Yes	
SERC RRO	Yes	
JEA	Yes	
PacifiCorp	Yes	
Electric Reliability Compliance	Yes	
PJM Interconnection	Yes	

Organization	Yes or No	Question 5 Comment
Southern Company	Yes	
Dynegy	Yes	
Exelon and its Affiliates	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	
Ingleside Cogeneration LP	Yes	
Texas Reliability Entity	Yes	
American Electric Power	Yes	
ITC	Yes	
Public Service Enterprise Group	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Tri-State G &T	Yes	
Ameren	Yes	
Kansas City Power and Light	Yes	
SMUD	Yes	

Organization	Yes or No	Question 5 Comment
NextEra Energy	Yes	
Xcel Energy	Yes	
Illinois Municipal Electric Agency	Yes	
California ISO		See associated SRC Comments

Response: Thank you for your comment.

Please refer to the responses for SRC comments.

6. The drafting team revised the Applicability section of PRC-001-2 to clarify which Protection Systems are applicable to Requirement R1. (The "Facilities" portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.) Do you agree with this revision to the Applicability? If not, please provide specific suggestions for improvement in the comment area.

Summary Consideration:

In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the "Effective Date" and "Compliance" sections of the standard is included with this fourth posting of PRC-027-1.

Organization	Yes or No	Question 6 Comment
American Electric Power	No	AEP appreciates the drafting team?s efforts to clearly identify the Protection Systems that are applicable to Requirement R1 but is concerned that the combination of Applicable Facilities in Section 4.2 and Requirement R1 may result in burdensome training requirements for the TOP, BA and GOP that do not provide an increase to BES reliability. In particular, the Applicable Facilities includes Protection Systems installed for the Generator Step-Up transformers, Station Service transformers and

Organization	Yes or No	Question 6 Comment
		the Excitation transformers. Nowhere does the standard limit the scope of this applicability to a subset of the Applicable Functional Entities. As a result, an auditor may interpret the standard to require that the TOP and BA be familiar with this level of generator protection for the units connected to their system.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		
Bonneville Power Administration	No	As described in the Facilities Section, the protection systems for which the requirements are applicable are ?Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements?. Since most Protection Systems are capable of isolating faulted elements without coordination, nearly all Protection Systems would be exempt from the requirements. While this would be acceptable to us, we don?t think this is what the drafting team intends.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		
Public Service Enterprise Group	No	Change section 4.2.1 (capitalized words show changes) as follows: ?4.2.1 - Protection Systems that are installed for the purpose of detecting AND ISOLATING Faults on BES Elements (lines, buses, transformers, etc.)?
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		
LG&E and KU Services	No	Did you mean PRC-001-3? If so, the response is, ?Yes.?
Response: Thank you for your comment. The drafting team did mean PRC-001-3. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		

Organization	Yes or No	Question 6 Comment
Flathead Electric Cooperative, Inc.	No	Do not believe that a DP-only entity would typically have Interconnected Elements that would necessitate inclusion, when the purpose is to protect the TO equipment.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		
Bureau of Reclamation	No	Reclamation requests that the drafting team clarify which Protection Systems ?require coordination? for isolating faulted Elements, or remove the phrase ?that require coordination? from the definition of Facilities.
Response: Thank you for your comment. Your comment is apparently referencing the Facilities section of PRC-027-1 and does not pertain to this question.		
City of Tacoma	No	The level of detail in the Applicability section appears to be inconsistent with the language in M1 ??training in basic relaying?? For this reason, it is recommended not to include the ?Facilities? portion.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		
Independent Electricity System Operator	No	We do not have any comment on the revised Applicability Section, but continue to express a serious concern with leaving PRC-001 in its present form. As indicated in our previous comment, we do not agree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. This is a training requirement and as such, it should be transferred to the appropriate PER standards. Providing training evidence does not demonstrate that the (operating personnel of) responsible entities are ?familiar with? the purpose and limitations of

Organization	Yes or No	Question 6 Comment
		protection system schemes applied in its area. c. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. In response to our previous comment, the SDT indicates that it ??recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.? We do not agree with this recommendation and hold the view that adding the issue to the NERC Issue Data Base is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT should propose a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee?s advice/direction for appropriate actions. We do not believe that the SDT or staff has brought this to the Standards Committee?s attention. Note that the Standards Committee is responsible for managing the standards development process and as such, can make an informed decision to either request the SDT to expand its scope (via an amended SAR) to address the PRC-001 issue, or to ask staff or the SDT to prepare a separate SAR to address the issue in parallel. Leaving the PRC-001 hanging out there without a recourse is not a satisfactory solution, and may in fact harm reliability. Once again, we urge the SDT to take the initiative to bring this issue to the Standards Committee, with a proposal to amend the SAR or prepare a new SAR, or seek its advice and direction before continuing work on this project.

Response: Thank you for your comment.

Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	Yes	(1) The title of the new PRC-001-3 standard does not seem to be the appropriate title since the standard addresses protection coordination issues, rather than requiring the system operators to be familiar with, and understand the protection system.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		
Duke Energy	Yes	Duke Energy believes that the Facilities section provides sufficient detail and clarity for this standard.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		
Ingleside Cogeneration LP	Yes	ICLP agrees that consistency between NERC standards is helpful. Since our Protection System maintenance program has been developed specifically to address BES relaying, it is a straight forward process to develop the related Operator training.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		
ITC	Yes	ITC Holding is in agreement with the clarification on which protection systems are applicable to requirement 1. Using the same definition as used in PRC-005-2 promotes consistency across the standards within the same category (PRC).
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		
DTE Electric	Yes	None
PacifiCorp	Yes	PacifiCorp would like to highlight a recommendation that was made by the drafting team on page 4 of Draft 3 of PRC-027-1 regarding Requirement R1 of PRC-001-2. The

Organization	Yes or No	Question 6 Comment
		drafting team has recommended via the NERC Issues Database that the future standards drafting team tasked with revising PER-005-1 incorporate the reliability objective of PRC-001-2 Requirement R1 into that revised standard. PacifiCorp is concerned with the potential overlap that could result from the failure to retire Requirement R1 in PRC-001-2 concurrent with the effective date of the new version of PER-005. To avoid the risk of entities having to comply with duplicative requirements under two currently-effective standards, the standards drafting team should include language in PRC-001-2 expressly confirming that compliance with the relevant requirement of the revised version of PER-005 will satisfy Requirement R1 of PRC-001-2 until such requirement is retired. In addition, there have been several proposals in the informal development of PER-005-1 that would expand the scope of applicability to include Generator Operators and Support Personnel. If R1 of PRC-001-2 is to be included in the new version of PER-005-1, the requirements of R1 could apply to additional functional entities. As such, any recommendation to move R1 of PRC-001-2 into the new version of PER-005-1 should be part of the PER-005-1 discussions that are currently taking place. At present, they are not. PacifiCorp would like to encourage more collaboration between drafting teams on the development of new draft standards and would like to thank the System Protection Coordination Standard Drafting Team for highlighting this recommendation.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		
SERC RRO	Yes	Regarding the applicability to the Generator Operator, the registered function of the Generator Operator could exist as a centralized corporate function as well as a remote function at the generation station. The requirements are probably aimed at the remote function, but if the corporate function embodies an electrical design group that is ?familiar? with the protection systems ?in their area?, is that sufficient for compliance? The draft includes a description of applicable ?Facilities?, but the question still applies.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		
Northeast Power Coordinating Council	Yes	There should be consistency between standards on this point.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 6 above.		
Florida Municipal Power	Yes	
ISO RTO Council Standards Review Committee	Yes	
Pepco Holdings	Yes	
FirstEnergy Corp	Yes	
Dominion	Yes	
Madison Gas and Electric Company	Yes	
Associated Electric Cooperative, Inc.	Yes	
Southwest Power Pool	Yes	
Cooper Compliance Corp	Yes	
JEA	Yes	

Organization	Yes or No	Question 6 Comment
Electric Reliability Compliance	Yes	
Southern Company	Yes	
Dynegy	Yes	
Exelon and its Affiliates	Yes	
Texas Reliability Entity	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Tri-State G &T	Yes	
Ameren	Yes	
Kansas City Power and Light	Yes	
Clark Public Utilities	Yes	
NextEra Energy	Yes	
Xcel Energy	Yes	
Essential Power, LLC		Did you mean PRC-001-3? If so, the response is, ?Yes.? We believe however that PRC-001 should be left as-is and PRC-027 should be made an exclusively TO-applicable standard, as explained elsewhere in these comments.

Response: Thank you for your comment.

The drafting team did mean PRC-001-3. Please see the statement related to the future of PRC-001 in the Summary Consideration for

Organization	Yes or No	Question 6 Comment
Question 6 above.		
California ISO		See associated SRC Comments
Response: Thank you for your comment. Please refer to the responses for SRC comments.		

7. **The drafting team provided a measure to accompany Requirement R1 of PRC-001-2. (The language in the measure was modeled after the existing language in the RSAW for PRC-001-2.) Do you agree with this measure? If not, please provide specific suggestions for improvement in the comment area.**

Summary Consideration:

In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the "Effective Date" and "Compliance" sections of the standard is included with this fourth posting of PRC-027-1.

Organization	Yes or No	Question 7 Comment
Public Service Enterprise Group	No	? Requirement R1 requires that ?Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.? This is too broad and vague with respect to which TOP, BA and GOP personnel are in the requirement?s scope. Subject to addressing PSEG?s additional comment of ?What is meant by ?familiar with? in R1?? in the bullet below, PSEG recommends that the requirement at least be revised to: ?Transmission Operator, Balancing Authority, and Generator Operator

Organization	Yes or No	Question 7 Comment
		personnel shall be familiar with the basic purpose and limitations of protection system schemes applied to the BES equipment and Facilities they control.?? M1 should describe methods other than documented training to meet R1 ? see the ?but not limited to? language. What is an alternative to documented training? What is meant by ?familiar with? in R1? Until ?familiar with? is better defined, M1 cannot be written.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
Essential Power, LLC	No	a. Did you mean PRC-001-3? b. It is not necessary to separate "limitations" from "purpose" in the VSL, and recommend that a single Severe VSL be used to cover all of R1 by using the requirement R1 verbiage "?familiar with the purpose and limitations of ?" PRC-001 moreover should remain as is, with PRC-027 being applicable to GOs under only very limited circumstances, as stated above. c. The word ?area? in R1 of PRC-001-3 needs to be defined for compliance to be measured and enforced. The area for GOs should be restricted to the plants they own, if PRC-001 is modified (see other comments).
Response: Thank you for your comment. The drafting team did mean PRC-001-3. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
LG&E and KU Services	No	a. Did you mean PRC-001-3? b. The word ?area? in R1 of PRC-001-3 needs to be defined for compliance to be measured and enforced. The area for GOs should be restricted to the plants they own, if PRC-001 is modified (see other comments).
Response: Thank you for your comment.		

Organization	Yes or No	Question 7 Comment
The drafting team did mean PRC-001-3. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
Ingleside Cogeneration LP	No	ICLP believes that the measure should identify that front-line operators are the target audience of the training. As a Generator Operator, we employ engineers, process developers, and operators ? and not all of these individuals require basic Protection System training. This ambiguity should be resolved while there is focus on PRC-001.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
Xcel Energy	No	Since there are no guidelines on who ?applicable personnel? are, and there are no guidelines on what type of training is required and how often, this measure serves little purpose should be removed. Measures and VSLs are overly complex and will be difficult to effectively track as written.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
American Electric Power	No	The examples of evidence in Measure M1 appear to be overly simplistic compared to the potential scope of R1.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
Northeast Power Coordinating Council	No	To specifically address Requirement R1, the Measure should be rewritten to stress that there be familiarity with the protection system schemes applied in its area. Suggest revising the Measure for Requirement R1 to read: Each Transmission Operator, Balancing Authority, and generator Operator shall have evidence that its appropriate personnel were made familiar with protection systems

Organization	Yes or No	Question 7 Comment
		in its area. That can be made easily auditable by having written summaries of the schemes, and have personnel sign offs after reading.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
Tri-State G &T	No	Tri-State believes that the Requirement R1 and Measure M1 need to refer more directly to the Facilities included in the Applicability section. A couple of options are presented below. Option 1: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of the following protection system schemes applied in its area: • Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.) • Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements. • Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability. • Protection Systems installed as a Special Protection System (SPS) for BES reliability. • Protection Systems for generator Facilities that are part of the BES, including: o Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays. o Protection Systems for generator step-up transformers for generators that

Organization	Yes or No	Question 7 Comment
		are part of the BES. o Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES). o Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays. If Option 1 is chosen, then the Facilities section in the Applicability can be removed. Option 2: M1. For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in the purpose and limitations of the Protection System schemes included in the Facilities section of the Applicability that are used within its area was provided to its applicable personnel.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
Independent Electricity System Operator	No	We do not agree with the proposed Measure for the reason as stated under Q6, above.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
Southern Company	No	While we agree with the changes made to the applicability section and the measurement section, we believe that it is not necessary to separate "limitations" from "purpose" in the VSL, and recommend that a single Severe VSL be used to cover all of R1 by using the requirement R1 verbiage "?familiar with the purpose and limitations of ?". Will compliance be evidenced by training records for individuals,

Organization	Yes or No	Question 7 Comment
		the content of the training, or both? How might the "familiar with limitations" and "familiar with purpose" be separately evaluated in an audit?
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
SERC RRO	Yes	The requirement still calls for ?familiarity? with the protection systems ?in their area?. The extent of ?familiarity? comes into question as well as the question of what constitutes ?their area?. The newly crafted Measurement attempts to give some detail as to what that means. But if training is the expected means of achieving compliance, why not just require the training? And if training is expected, then the scope of that training should be related to application of a systematic approach to training, not a scope identified by the SDT, or an area arbitrarily selected by the auditors.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
Ameren	Yes	(1) The measure was provided for PRC-001-3, not PRC-001-2.
Response: Thank you for your support. The drafting team did mean PRC-001-3. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
FirstEnergy Corp	Yes	Although we agree with the proposed change, we have reservations of having a standard with only 1 requirement. Please see our comments on Question #8.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
Dominion	Yes	Dominion believes the reference to PRC-001-2 is incorrect and should be noted as PRC-001-3 as PRC-001-2, Page 11, cites ?Measures and Compliance Elements will be

Organization	Yes or No	Question 7 Comment
		added to a later draft.? Dominion supports the measure accompanying Requirement 1, as included in PRC-001-3. Dominion also notes that the reference to the RSAW for PRC-001-2 is incorrect and should reference the RSAW for PRC-001-1.Dominon was unable to locate a draft of RSAW PRC-001-2 or PRC-001-3 on the Standards Under Development NERC webpage or under any category, on the NERC RSAW page.
Response: Thank you for your support. The drafting team did mean PRC-001-3. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
ITC	Yes	ITC Holdings is in agreement to add the measure to the standard to be in-line with the language in the RSAW for PRC-001-2.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
DTE Electric	Yes	None
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
Bureau of Reclamation	Yes	Reclamation thanks the drafting team for assisting Registered Entities with the transition from PRC 001 to PRC-027 by incorporating the RSAW language to ensure continuity of compliance.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
Southwest Power Pool	Yes	While we concur with the proposed measure, there does appear to be a mismatch between the requirement and the measure. See our comment in Question 8 below

Organization	Yes or No	Question 7 Comment
		to address this issue.
Response: Thank you for your comment. Please see the statement related to the future of PRC-001 in the Summary Consideration for Question 7 above.		
Florida Municipal Power	Yes	
ISO RTO Council Standards Review Committee	Yes	
Pepco Holdings	Yes	
Duke Energy	Yes	
Bonneville Power Administration	Yes	
Madison Gas and Electric Company	Yes	
Associated Electric Cooperative, Inc.	Yes	
Cooper Compliance Corp	Yes	
JEA	Yes	
City of Tacoma	Yes	
PacifiCorp	Yes	
Electric Reliability Compliance	Yes	

Organization	Yes or No	Question 7 Comment
Dynegy	Yes	
Exelon and its Affiliates	Yes	
Manitoba Hydro	Yes	
Texas Reliability Entity	Yes	
American Transmission Company	Yes	
Idaho Power Co.	Yes	
Kansas City Power and Light	Yes	
Clark Public Utilities	Yes	
SMUD	Yes	
NextEra Energy	Yes	
California ISO		See associated SRC Comments
Response: Thank you for your comment. Please refer to the responses for SRC comments.		

8. **If you have any other comments that you haven't already provided in response to the above questions, please provide them here.**

Summary Consideration:

There were numerous comments similar to those found in earlier questions. The drafting team responded to each of those comments below but they are not included in this summary for brevity.

Various commenters suggested minor revisions to the standard that were accepted by the drafting team, they include:

- Updated the Background section
- Modified Requirement 4 and separated it into two Requirements, R4 and R5 for clarity
- Modified the Figures and associated descriptions in the Guidelines and Technical Basis section to provide more clarity
- Changed the word "demonstrates" to "documents" in the definition of the PSCS
- Removed section 4.2.1 from the Facilities section of the Applicability
- Inserted the word "permanent" and the phrase "associated with the Interconnecting Element" in Requirement R3, Part 3.3
- Changed the word "modification" to "addition" in the new Requirement R5 (old Requirement R4, Part 4.2)

Some commenters believed the standard should not apply to separate functional entities within the same registered entity. The response explained that the drafting team does not agree because there are cases where the Transmission Owner and Generator Owner are part of the same Registered Entity but separate technical groups are involved in performing the required Protection System Coordination Studies. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: "In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities."

A few commenters continue to disagree with the 10% deviation trigger in Requirement R2. The threshold of 10% was selected based on the experience of drafting team members, discussions with members of various regional protection and control committees, and the recognition that there are margins of error in models and in protection system accuracies. The drafting team contends that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. No change was made to the standard.

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LG&E and KU Services	a. PRC-027-1, R3.3 should be limited to Protection Systems associated with Interconnected Elements b. There is no clear indication of need to change the present system. The SDT states on p.21 of PRC-027 that ?[t]he drafting team has no evidence there is widespread miscoordination between Owners of Facilities,? and ?records collected for reliability standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.? The purpose statement for PRC-001-3 needs to be changed to match the content of the sole requirement. If this one requirement is to be absorbed by PER-005, consider keeping the purpose and moving the content of PRC-027 back into PRC-001. c. Please retain one measure per requirement so that the Measurement numbers in PRC-027-1 match the base requirement number. The evidence required for each sub part of each base requirement can be described in the same section as the other sub parts.
Response: Thank you for your comment. a. The drafting team made the suggested change to Requirement R3, Part R3.3. b. The drafting team discussed your suggestions and determined they are not feasible. c. The drafting team's method for writing and numbering the measures as well as the one you describe are both permissible. The drafting team prefers the method they have chosen.	
Seminole Electric Cooperative Inc.	(1) In proposed PRC-027-1 R2, Seminole believes that the Reliability Coordinator (RC) should have the responsibility of performing any studies or analyses and the distribution of those studies/analyses required under R2 instead of the Transmission Owner (TO). In peninsular Florida, the RC has access to the data needed for the analyses and having a single entity perform the analyses and distribution will assure uniformity across the region.

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	(2) In proposed PRC-027-1 R2-2.2.1., Seminole believes the 10% threshold for fault current is too low, as this percent change occurs daily. Seminole recommends the 10% threshold value be increased to 20% for fault current. (3) In proposed PRC-027-1 R2, is the 10% change in fault current study based on the individual TO?s system contribution as an island at the interconnection bus, or does it include all other interconnection that border the TO?s system that could provide fault current, i.e., how many buses out from the TO?s other interconnections does the study require for determining available fault current? (4) In proposed PRC-027-1 R2, Seminole believes that the requirements and guidelines for the Protection System Coordination Study (PSCS) need to be more specific and give additional detailed methodology. (5) In proposed PRC-027-1 R3-3.1, it should be noted that current and voltage ratio changes do not necessarily indicate a change in the protection system if the protective relay set points are adjusted accordingly. Therefore, R3-3.1 should be revised to reflect that certain ratio changes do not require notification.

Response: Thank you for your comment.

(1) The Functional Model assigns real-time operating responsibilities to the Reliability Coordinator, and Requirement R2 in PRC-027-1 is in the planning horizon. The drafting team assigned the responsibility of performing the short circuit studies in Requirement R2 to the Transmission Owner (TO) because the TO has all the data required to run the studies.

(2) The threshold of 10% was selected based on the collective experience of drafting team members, discussions with members of various regional protection and control committees, and the recognition that there are margins of error in models and in Protection System accuracies. As stated in the Guidelines and Technical Basis section of the standard, the short circuit studies performed for this function typically assume maximum generation and all Facilities in service. The drafting team contends that this value will not change daily. No change was made to the standard.

(3) The 10% change is based on the total Fault current available at the interconnecting bus.

(4) The drafting team contends the Guidelines and Technical Basis section of the standard provide sufficient guidance on the methodology of the PSCS and intentionally allowed flexibility for the entities to comply with the standard. No change was

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made to the standard. (5) The drafting team contends that any transformer ratio change that modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s) needs to be provided to the other entities associated with the Interconnecting Element(s). No change was made to the standard.	
Manitoba Hydro	(1) The wordings of the sentence ?Examples of Protection Systems where technical justifications may be used include? under heading ?Requirement R2 in the ?Application Guidelines? are unclear. MH suggests that It read as follows: ?Examples of Protection Systems that are not affected by the fault current change include?.Also, under the same section, it?s very confusing as to what relays the following refers to:4. Reverse power, definite time &/or time overcurrent elements: Designed to coordinate during maximum generation with the transmission system under normal operating conditions and includes the calculation of the percent deviation between the under single contingency conditions regardless of Fault current. Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.). (2) Protection System Coordination Study definition - for clarity, replace the word ?that? with the word ?which? and insert the word ?that? between ?demonstrates existing?. Moreover, consider replacing the words ?for clearing Faults? with ?during Faults? for consistency with the purpose of the Standard. The suggested definition should read ?A study which demonstrates that existing or proposed Protection Systems operate in the desired sequence during Faults. This definition should also be changed in the rational for R1 section and Implementation Plan document if it is an accepted change by the SDT. (3) Background - references are made to standards PRC-001, PRC-027, TOP-003, PRC-005, etc. in this section, which in some cases, do not include the title following the standard number. For consistency, the title should be included, or in the least referred to at the first instance of the standard number in this section. (4) Other Aspects of Coordination of Protection Systems Addressed by Other Projects -

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	replace the period ?.? at the end of the last paragraph with a colon ?:? .Moreover, follow each project number with its title for consistency and clarity. (5) R1.2 - the words ?Protection Systems? and ?Currents used? should be written as ?Protection System(s)? and ?Current(s) used? to maintain consistency with the rest of the paragraph.As a note, consider changing all instances of the words ?Protection Systems?, ?Currents?, ?owners? and ?Interconnected Elements? to ?Protection System(s)?, ?Current(s)?, ?owner(s)? and ?Interconnected Element(s)?, to maintain consistency throughout the document. (6) R2.1 - remove the words ?Protection System Coordination Study?, leaving only the acronym ?PSCS?, because it has been previously defined in the document. (7) R2.2.1 and M5 - add an ?s? or ?(s)? to both ?Protection System? and ?Interconnected Element?. (8) M4 - replace ?is? with ?includes? and ?that contains? with ?which contain?. (9) All measures - for consistency, the phrase ?may include, but is not limited to,? should be added to each measure. (10) R4.2 - place brackets around the ?s? in the following words ?modifications? and ?issues? for consistency with the rest of the document. Please continue this change throughout the Standard and Technical Guideline document for consistency. (11) 1.2 Evidence Retention - is it necessary to state that ?The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.? since this information is already included in the CMEP. (12) R4.2 and M10 - the words ?proposed changes and modifications? should be changed to ?proposed changes and additions? to mirror the wording in R3.1.

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Response: Thank you for your comment. (1) The drafting team contends the wording is clear and is not confusing. The conditions described in each of the bullets apply to any of the relays listed. No change was made to the standard. (2) The drafting contends the proposed definition is both technically and grammatically correct. No change was made to the standard. (3) The drafting team contends the standard number is sufficient to adequately reference the standards in the Background section. No change was made to the standard. (4) The drafting team made the suggested changes. (5) The drafting team made the suggested changes to Requirement R1, Part 1.2. (6) The drafting team made the suggested changes. (7) The drafting team made the suggested changes. (8) The drafting team contends that Measure M4 is accurate and grammatically correct as proposed. No change was made to the standard. (9) The drafting team included “may include, but is not limited to” only in instances where it believed the phrase was appropriate. No change was made to the standard. (10) The drafting team moved the content of Requirement 4, Part 4.2 to Requirement 5, and made your suggested changes. (11) This is “boiler plate” language used in the “Evidence Retention” section of all Reliability Standards. (12) The drafting team moved the content of Requirement 4, Part 4.2 to Requirement 5, and made your suggested changes.	
Ameren	(1) In Application Guidelines for R1, please add ?A Protection System Coordination Study includes, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed.? We request adding it just after the definition of a PSCS. This will more clearly align the Application Guidance with R1.2. (2) Under Requirement 2, studies are referred to as ?most recent? and ?present? which

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	is confusing and could be considered synonymous. We ask the SDT to change this terminology to replace ?most recent? with ?previous? study and ?present? with ?new? study in all places within the standard where they exist. (3) Requirement R3, 3.1 first bullet is both broad (new installation, replacement with different types) and specific (modifications to protective relays or protection functions settings, communications, CT/PT ratios). The 3.1 text itself clearly targets changes or additions to existing or new Facilities that modify conditions that impact coordination of Protection Systems. We request the SDT to replace the existing bullet points to clarify areas of this emphasis to these bullet points:?? Change in Protective Relay Types or Functions? Change in Communication System(s) that interface with Protection System(s)? Change in connected voltage (VT) or current (CT) source ratios? Change to transmission system Element(s) that alters impedance? Change to generator unit (s) that alters impedance, or? Change to generator step-up transformer (s) that alter in impedance? (4) We request the SDT to clarify 4.2 by combining 4.2.1 into it, thus removing the separate 4.2.1. Please reword as follows: ?These requirements contained herein are applicable to each 4.1 Functional Entity that owns Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.?

Response: Thank you for your comment.

(1) The Guidelines and Technical Basis section of the standard for Requirement R1, Part 1.2 indicates what minimum information must be included in the PSCS, and provides more detail rather than simply reiterating the language in the standard. No change was made to the standard.

(2) The drafting team used “present” to qualify the short circuit study and “most recent” to qualify the Protection System Coordination Study. These are two different studies. Only when the differential between the resulting values in the two types of studies exceeds 10% does a new Protection System Coordination Study need to be performed. No change was made to the standard.

(3) The first bullet contains changes made to the Protection System(s) component types, whereas the other bulleted items refer to

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different types of changes that could change the impedance in the system. No change was made to the standard. (4) Based on yours and other stakeholder comments, the drafting team revised the Applicability section to remove 4.2.1.	
Southern Company	(a) The purpose statement for PRC-001-3 needs to be changed to match the content of the sole requirement. If this one requirement is to be absorbed by PER-005, consider keeping the purpose and moving the content of PRC-027 back into PRC-001. (b) Please retain one measure per requirement so that the Measurement numbers match the base requirement number. The evidence required for each sub part of each base requirement can be described in the same section as the other sub parts. (c) There is no equation found in R2.2. (d) In R3.3, it is not clear when the 30 days starts - is it the 30 days following the change(s)? (e) R3.3 should be limited to Protection Systems associated with Interconnected Elements. (f) 4.2 can hold an entity hostage if the other Interconnected Element owner does not/will not accept/reject the changes.
Response: Thank you for your comment. (a) In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another	

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	body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the "Effective Date" and "Compliance" sections of the standard is included with this fourth posting of PRC-027-1. (b) The drafting team's method for writing and numbering the measures as well as the one you describe are both permissible. The drafting team prefers the method they have chosen. (c) The equation was initially missing in the posted version due to formatting errors that occurred during the posting process. The corrected standard was posted on the NERC web site on June 21, 2013. (d) The drafting team modified the language for clarity. Yes, within 30-days of making the change is correct. (e) The drafting team made the suggested change to Requirement R3, Part R3.3. (f) The drafting team acknowledges that entities may have differing protection philosophies. Based on yours and other stakeholder comments, the drafting team separated Requirement R4 into two Requirements, R4 and R5. The new Requirement R5 states that any identified coordination issues must be addressed prior to the implementation of any changes or additions to the Protection System(s) associated with the Interconnecting Element. The drafting team contends that any conflict resolution should be handled through normal business practices.
Pepco Holdings	1) The SDT states that ?the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address the appropriate use of time delays in relays?. However, a word search of the 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. The mention of ?the appropriate use of time delays in relays? in the 2003 Blackout Report was in the context of the actuating time of relays in response to system overload conditions, and generator protection to voltage and frequency excursions during stressed system conditions. The concern was that relays operated on overload before system operators could react and that some generators tripped (exacerbating the collapse) before other system schemes (UFLS or UVLS) could operate. The solution was

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	not to increase the time delay on Zone 3 relays (which would have been intolerable for fault clearing purposes) but to address the relay loadability issue in PRC-023, to make them immune from operating under heavy load conditions. Similarly the premature tripping of generators on voltage and frequency protection during stressed system conditions (not fault conditions) and coordination with system UFLS and UVLS schemes was discussed in the report. Likewise those issues have now been addressed, or are being addressed, in PRC-006, PRC-010, PRC-022, PRC-019, and PRC-024. Similarly in the recent Southwest Blackout of 2011 the operation of relay schemes during overload conditions was a contributing factor. There was again no evidence of miscoordination of relay schemes during fault conditions. The unexpected operation of relays and SPS?s during overload conditions could have been avoided by proper application of existing standards PRC-023 and PRC-014-0. Based on the above, where is the historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions? Reliability Standards should be adopted based on a need to address a known, or probable, reliability issue. As such, although PHI supports the overall desire to ensure that protective systems are ?properly coordinated?; PHI sees little value in developing a new Reliability Standard to address something that is routinely practiced and which has not been demonstrated to be a contributor to major system disturbances, or cascading outages. Even the SDT in their rationale for Requirement R1.1 stated that they have no evidence that there is widespread miscoordination between Interconnected Facilities. In lieu of a formal standard to address relay coordination during faults, a simple technical reference document on Protective System Coordination issues may provide equal benefit to the industry. The above comment was also submitted with Draft 1 of the standard. In their response the SDT stated that PRC-027 was being developed in response to FERC Order 693. However, Order 693 only directs NERC to address specific deficiencies in PRC-001 surrounding certain measures and levels of non-compliance relating to the notification and response to the detection of failures in relay protection systems. As such, PHI believes PRC-027 goes well beyond what is was directed by FERC, and the stated purpose of the SAR. PHI urges the SDT to revisit FERC Order 693 and revise this

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	standard as appropriate to address only the stated FERC directives. 2) Based on the arguments presented in the above comments, including the lack of historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions, PHI suggests that NERC conduct a Cost Effective Analysis (CEA) to provide information about cost impacts (e.g., implementation and ongoing compliance resource requirements) of this draft standard and its relative effectiveness in preventing widespread blackouts, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of this standard. 3) Requirement R2, Parts 2.1.1 and 2.1.2: Remove the term ?interconnecting bus? and replace it with the phrase ?point of interconnection between the Entities.? The point of interconnection between the entities is more descriptive in that the interconnection point may not be a physical ?bus?, but rather the terminals of a line disconnect switch, terminals of a breaker, specific transmission pole, etc. Even though the point of interconnection is often modeled in a short circuit program as a ?bus?, the term ?interconnecting bus? has no physical meaning. 4) Requirement R3, Part 3.3: A footnote should be added stating that this requirement does not apply to those temporary setting changes that sometimes are applied during commissioning, maintenance, or investigative testing activities to verify performance of individual protective elements, provided the original settings were returned upon the conclusion of the testing activity. For example, in multifunction relays when testing backup time delayed protective elements (i.e., zone distance or time overcurrent elements) it may be necessary to temporarily disable high speed elements (i.e., pilot or zone 1 elements). In response to this comment the SDT responded that it ?believes temporary settings changes are addressed in TOP-002, which incorporated Requirements R5 and R6 from PRC-001-1. Temporary settings applied (or changed) to perform maintenance testing of a relay would not have an effect upon overall coordination of the Protection System, as the relay would likely be taken out of service for such testing.? PHI agrees with this conclusion, however, this standard does not specifically exclude these

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	temporary changes from Part 3.3. Therefore an auditor may conclude that they are in scope for this standard. As such, PHI suggests Part 3.3 be qualified with a footnote to specifically exclude these types of temporary settings. 5) Based on the commentary accompanying Figure 3 in the Guidelines and Technical Basis document it appears that a Protective System Coordination Study (PSCS) is required only if there are protective systems installed on breaker C for the purpose of detecting faults on the BES system. Is there a recommended criteria or generation size below which there is no need for a PSCS, or for a dedicated ?fault protection system? at Breaker C to detect faults on the Interconnected BES element? For example, suppose all generation downstream of the Distribution Provider?s system is comprised of solar installations with non-islandizing inverters. In these cases, it would be unusual to install fault detection systems ?looking into? the BES system at breaker C even though there is generation installed downstream. The non-islanding inverters with 27/59 and 81O/U protection would isolate the generation upon loss of transmission source when Breakers A and B opened. Similarly, if a small synchronous generator was installed on a downstream distribution feeder with sufficient connected load to ?swamp? the generator upon the loss of transmission source, protective relays at the generator location, rather than at Breaker C, would operate to remove the generator upon loss of the transmission system source. In both of these examples, even though there may be overcurrent protection, or fuses, installed on the high side of the transformer for transformer faults, there is no dedicated fault protection system installed at breaker C for the purpose of detecting faults on the transmission system, and as such there would be no need for a PSCS. Is this correct?

Response: Thank you for your comment.

1) The reference to Recommendation 21C has been removed from the standard.

2) The drafting team forwarded your recommendation to NERC staff.

3) The drafting team contends that the figures in the Guidelines and Technical Basis section of the standard clearly illustrate the "interconnecting bus."

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4) The drafting team added the word "permanent" to Requirement R3, Part 3.3 to address your comment. 5) The drafting team intended Figure 3 to be interpreted as you suggest.	
Xcel Energy	1) PRC-027-1 R3.2 has a deadline based on the date of receiving a request. There should more details regarding what constitutes receiving a request. If informal channels are used, there may be disagreement about whether the 30 day deadline was met.The complexity of this standard becomes all the more evident when looking at ways to implement and track all the measures. For many of the measures, the only practical way to capture time frames is to tie communications with an interconnected entity to a task within an established schedule. Communications with interconnected entities will likely need to become more limited and formal to become more trackable. Bringing tractability to emails and other communications for evidence will be a significant issue, with the need to capture communications of out-side resources performing studies as well as the use of secure email requiring tedious offloading or screen captures of communications from secure servers. It would be recommended that acceptable evidence demonstrating the time frames should allow for documented processes along with activity schedules providing start and completion dates. More detailed evidence should be signed and verified studies, which indicate that validated models and remote settings have been utilized in the analysis. Here are our specific recommendations by requirement and measure: a) Requirement R1- R1.1.3- It would be recommended to be consistent with the time frame as specified in 1.1.2 and change the specified calendar months to read ?or within 12 calendar months of being notified of a change as described in Requirement R3, Part 3.3.? M1, M2 - Acceptable evidence demonstrating time frames should allow for documented processes along with activity schedules providing start and completion dates. (VSL) Violation Security Levels- Each security level should provide consistent time frames to avoid confusion in tracking. b) Requirement R2 ?R2.2- Allowance should be made to allow for tracking of fault level trends at the bus based on a 10% change in fault level for the year of the coordination study. M5 - Acceptable evidence demonstrating time frames should allow for

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	documented processes along with activity schedules providing start and completion dates.(VSL) Violation Security Levels- Each security level should provide consistent time frames to avoid confusion in tracking. c) Requirement R3 ?M7 ? A data request should indicate that it is being made per requirement R3 of PRC-027 to be measured under M7. M6, M7, M8- Acceptable evidence demonstrating time frames should allow for documented processes along with activity schedules providing start and completion dates. d) Requirement R4?R4- Study submittals should be required to stipulate that the study is being submitted per requirement R4 of PRC-027 to be measured under M9. M9, M10-Acceptable evidence demonstrating that the time frames have been met should allow for documented processes along with activity schedules providing start and completion dates. 2) 4.2.1 Applicability: For Generator Owners, many elements that are covered under the PRC-019, PRC-024 and PRC-025 (and future Phase 3 Loadability Standards) also fall under the Facilities Section of this draft of PRC-027-1, as the functions exist for the sole purpose of allowing coordination for faults to clear external to the generator. The elements covered by other standards should be excluded from applicability, in order to avoid a double jeopardy situation.Instead, we recommend that a list of applicable elements be identified. Typical functions are identified below. We believe these to be the only functions applicable to the standard as far as a GO is concerned.- Ground Time Overcurrent Relay ? (Directional Towards the System) (51G) - Neutral Time Overcurrent Relay ? (Directional Towards the System) (51N) - Ground Directional Time Overcurrent Relay ? Directional Toward Transmission System (67G) - Negative Phase Sequence Overcurrent (46) In addition, please consider adding a list of excluded elements, such as these:- Phase Distance (21) (Covered under PRC-025) - Volts/Hz (24) (Covered under PRC-024) - Undervoltage (27) (Covered under PRC-024) - Reverse Power (32) (Not applicable to standards as it is protection for the generator) - Loss of Field (40) (Covered under PRC-019) - Inadvertent Energization (50/27) (Not applicable to standards as it is protection for the generator) - Breaker Failure (50BF) (Not applicable to standards as it is protection for

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	the generator) - Phase Time Overcurrent Relay (51) (Covered under PRC-025) - Phase Time Overcurrent Relay ? Voltage-Restrained (51V-R) (Covered under PRC-025) - Phase Time Overcurrent Relay ? Voltage Controlled (51V-C) (Covered under PRC-025) - Overvoltage (59) (Covered under PRC-024) - Field Overvoltage (59E) (Covered under PRC-019) - Stator Ground (59GN/27TH/64S) (Not applicable to standards as it is protection for the generator) - Field Ground (64F) (Not applicable to standards as it is protection for the generator) - Phase Directional Time Overcurrent Relay ? Directional Toward Transmission System (67) (Covered under PRC-025) - Field Overcurrent (76E) (Covered under PRC-019) - Out of Step (78) (Covered under Future Phase 3 Loadability Standards) - Frequency (81) (Covered under PRC-024) - Differential (87) (Not applicable to standards as it is protection for the unit) Alternatively, perhaps a table listing excluded elements could be added to the back of the standard, and referenced in the 4.2.1 Applicability section. Here is an example of what 4.2.1 might look like: ?4.2.1 Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements with the exclusion of the elements listed in table XXX. ? 3) Regarding R2 M3 - Our technical justification to exempt the above excluded elements is: a) duplication in applicability to other standards, and b) the type of fault. Mandating technical justification beyond these two points puts an unnecessary burden on industry resources.

Response: Thank you for your comment.

1) Measures support requirements by providing examples of evidence that can be used to demonstrate compliance; they are not mandatory or enforceable. For some requirements, only one type of evidence may be acceptable but for many requirements, a range of evidence could be acceptable and a phrase such as “evidence that may include, but is not limited to…” is used in the measure.

<table>
<tr><th>Organization</th><th>Question 8 Comment</th></tr>
<tr><td colspan="2">a) While most changes associated with Requirement 3, Part 3.3 may not impact Protection System coordination; the drafting team contends these changes need to be communicated. If a new PSCS is required, then the six month window (Requirement R1, part 1.1.4) is more appropriate than a twelve month window because a Protection System change has been made - not just a modeled change in Fault current. The drafting team contends the evidence suggested in the measure is appropriate and necessary to show that the PSCS has been completed. The drafting team contends that the varying time frames for the different parts of Requirement R1 are appropriate based on the different actions and the associated time frames of those actions. No change was made to the standard.

b) The change in Fault current is based on the cumulative change in Fault current since the last PSCS because Fault currents can gradually change based on system modifications that are unrelated to interconnections. Those Fault currents could be significantly different from the most recent PSCS even though an annual change may never reach the 10% threshold. The drafting team contends the evidence suggested in the measure is appropriate and necessary to show that the PSCS has been completed. The drafting team contends that the varying timeframes for the different parts of Requirement R1 are appropriate based on the different required action time frames in the different parts. No change was made to the standard.

c and d) The drafting team believes that the format of the data request is best left to the requesting entity and that the evidence suggested in the measure is appropriate and necessary to show that the PSCS has been completed. No change was made to the standard.

2) In reference to the Standards noted (PRC-019,024,025), the drafting team does not believe there is conflict. The noted standards (PRC-019,024,025) provide guidance for the setting of certain control and protection functions related primarily to generator capabilities, not for the coordination of Protection Systems with other owners for performance during Faults. The drafting team did not include a list of protection functions included or excluded; however such guidance can be found in the NERC Technical Reference Document written titled “Power Plant and Transmission System Protection Coordination” written by the System Protection and Control Subcommittee. Specific to one example that was noted: Back-up Distance (21) - although other standards may provide guidance on the setting of this function from a loadability perspective, the drafting team contends that it is important to coordinate this setting with other owners to ensure the setting (both reach and time) does not cause the generator to trip for normally cleared Transmission System Faults.

3) Please see the response immediately above.</td></tr>
<tr><td>Kansas City Power and Light</td><td>1) The definition of Protection System Coordination Study should be changed to ?A study that documents the intended sequence of operation for clearing faults of an existing or</td></tr>
</table>

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	proposed Protection System.? The word ?demonstrates? implies that live testing should be conducted to prove the sequence of operation. 2) In the Rationale for R1, Part 1.1.2, the following portion should be deleted, ?e.g. when a line is protected by dual current differential systems with no backup elements set that are dependent upon fault current.? The deleted portion should be replaced with ?Refer to the Application Guidelines for Requirement R2 for examples of protection systems where technical justifications may be used.? 3) Requirement R2 specifies a 10% change in fault current as the trigger for a review of the Protection Coordination. We believe that the only time that a Protection Coordination Study should be required is if the fault current increases by more than 10%. Fault studies are typically conducted with all generation on, but we know that this is not the normal system configuration year round and the system could be operating below the 10% fault current threshold. Unit outages are anticipated and fault detecting elements are set to operate even during outage conditions. Elements that coordinate at higher fault current values will coordinate at reduced values. Our suggested change would not preclude a Registered Entity from initiating a Protection Coordination Study upon the reduction of fault current by 10%.
Response: Thank you for your comment. 1) The drafting team accepted your suggestion and changed and the word "demonstrates" to "documenting" in the definition. 2) The drafting team incorporated your suggested change. 3) The Guidelines and Technical Basis section of the standard indicate that the short circuit studies performed for this function typically assume maximum generation and all Facilities in service. The drafting team contends that if changes are made to the Transmission system that result in lower Fault currents for those conditions that reach the trigger threshold, then a new PSCS is required. No change was made to the standard.	
Dominion	1). Under Requirement 2 (Page 8 of Redline Version), studies are referred to as ?most recent? and ?present? which is confusing and could be considered synonymous. Recommend changing this terminology to replace ?most recent? with ?previous? study

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	and ?present? with ?new? study in all places within the standard where they exist. 2). Requirement R3, 3.1 first bullet (Page 10 of Redline Version) is both broad far reaching (new installation, replacement with different types) and specific (modifications to protective relays or protection functions settings, communications CT/PT ratios). 3.1 Clearing targets changes or additions to existing or new Facilities that modify conditions that impact coordination of Protection Systems. Recommend changing bullets to clarify areas of this emphasis to:? Change in Protective Relay Types or Functions? Change in Communication System(s) that interface with Protection System(s)? Change in connected voltage (VT) or current (CT) source ratios? Change to transmission system Element(s) that alters impedance? Change to generator unit (s) that alters impedance? Change to generator step-up transformer (s) that alter in impedance 3). In Application Guidelines ? Example Process (Page 30 of Redline Version) the second bullet indicates that a single study can be used whereas in R1 1.1.3 it states that ?each? entity shall perform a PSCS. Recommend clarification in this example to reflect Note that is included in Rational for R1 that indicates in cases where a single group performs overall study for the interconnection for both entities. This reference may lead to confusion in the example. 4). Wording is confusing in PRC-027-1 Applicability Section (Page 3 of Redline Version). Suggest combining 4.2 and 4.2.1 into something like ?Protection Systems owned by the Functional Entities in 4.1 are applicable if they are installed for the purpose of detecting Faults on Interconnected Elements of the BES and require coordination for isolating those faulted Elements?. 5). There are numerous locations in the standard that note that ?Protection System Coordination Studies are typically performed assuming maximum generation and all Facilities in service.? Given the complexities of system configurations, it is not always the case that this scenario (Max Gen and All Facilities In) will be the best case under which to verify proper coordination. Recommend removing this note and require entities to determine the best scenario under which to evaluate coordination. The presence of this

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	note may create unintended bias. 6). Dominion agrees with SERC PCS comment: ?Please change Figures 3 and 4 in the Applications Guidelines section so that ?Interconnected Element? is adjacent or points to the line between Breaker C and the point of connection (tap point) on the line between Breakers A and B. It clarifies these examples by having the Figures align with your wording. (The Figures presently imply that the line between Breakers A and B is the ?Interconnected Element?.)
Response: Thank you for your comment. 1) The drafting team used “present” to qualify the short circuit study and “most recent” to qualify the Protection System Coordination Study. These are two different studies. Only when the differential between the resulting values in the two types of studies exceeds 10% does a new Protection System Coordination Study need to be performed. No change was made to the standard. 2) The first bullet contains changes made to the Protection System(s) component types, whereas the other bulleted items refer to different types of changes that could change the impedance in the system. No change was made to the standard. 3) The drafting team believes that the Note in the rationale box for Requirement R1 and the second bullet in the Example Process are worded adequately and sufficiently to avoid any confusion about what is required. No change was made to the standard. 4) Based on yours and other stakeholder comments, the drafting team revised the Applicability section to remove 4.2.1. 5) The drafting team recognizes that engineering judgment will be used by entities when modeling the system for the PSCS. Since at least two entities will be performing or reviewing the PSCS, the drafting team believes that an appropriate system configuration will be used. There is no way to measure whether entities have determined “the best scenario under which to evaluate coordination.” No change made to the standard. 6) The drafting team revised Figures 3 and 4 to indicate that the tap line is the Interconnecting Element.	
Bureau of Reclamation	1. Reclamation requests that the drafting team clarify what "acceptable evidence" it envisions for PSCSs. For an example, is a PSCS acceptable if the document contains (a) Date of study,

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	(b) Deviation of short-circuit currents, (c) System change, (d) all recipients, etc. We appreciate if you can include an example form/document as acceptable evidence. Reclamation would appreciate if the drafting team added a sample PSCS template that would be considered acceptable evidence. 2. In order to avoid similar vagueness of coordination issues that were problematic under PRC-001, Reclamation would appreciate if the drafting team clarifies what a PSCS should contain (e.g. which relay element(s) is required to coordinate with, how to show it as the evidence, etc.)The PRC-025 documents may provide helpful examples. 3. Regarding R1 & M1, if a PSCS shows no impact on the existing coordination (no setting changes are required), would an entity still have to send neighboring utility(s) the entire PSCS supporting study or would a brief statement of the study results suffice? Reclamation requests that the drafting team clarify the acceptable evidence. 4. Reclamation suggests that R2 should be revised to read, ?For each interconnected element on its System, the TO shall, once every 60 calendar moths, technically justify if a fault current has changed more than 10% but does not affect to the Power System coordination, or ?? rather than "techincally justify why Fault current does not affect the Protection System coordination." 5. Reclamation requests clarification of the items requiring coordination listed in R3.1. Reclamation believes that the current list implies that any changes in relay equipment or settings would require coordination.

Response: Thank you for your comment.

1. The drafting team does not believe it should prescribe the entire content (inputs or results) of the PSCS. The minimum elements of a PSCS summary are listed in Requirement R1, Part 1.2 and additional information is provided in the Guidelines and Technical Basis section of the standard in the section for Requirement R1. No change was made to the standard.

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2. The drafting team does not believe it should prescribe the entire content (inputs or results) of the PSCS. The minimum elements of a PSCS summary are listed in Requirement R1, Part 1.2 and additional information is provided in the Guidelines and Technical Basis section of the standard in the section for Requirement R1. No change was made to the standard. 3. Requirement R1, Part 1.2 only requires that a summary of the PSCS be provided to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s), regardless of whether there was impact on the existing coordination. No change was made to the standard. 4. The drafting team revised Requirement R2 to eliminate the use of a technical justification. 5. Your interpretation of Requirement R3, Part 3.1 is correct. Please reference the Guidelines and Technical Basis section of the standard in the section for Requirement R3 for more information.	
Bonneville Power Administration	1. The definition of Protection System Coordination Study is inadequate because it does not address what type of faults must be studied or where on the system the faults need to be applied. 2. R1.1.2 uses the term interconnecting bus. This is not a common term and requires a definition.
Response: Thank you for your comment. 1. The drafting team believes that the definition, as written is adequate. The NERC Glossary of terms "Fault" is used to include all types and locations of Faults. 2. The drafting team believes that the figures in the Guidelines and Technical Basis section of the standard clearly illustrate the "interconnecting bus."	
Exelon and its Affiliates	a. For voltage levels at 345Kv and above (EHV), our standard Protection System design utilizes two high-speed pilot schemes, and includes time-delayed backup protection. Due to pilot scheme redundancy, the operation of time-delayed backup elements is an extremely rare event. Our time-delayed backup protection is intended to serve only as a safety net for extreme events and we do not believe it is cost effective to study time coordination of these elements across our EHV systems. We believe that in cases where high speed protection schemes are redundant, that is designed such that loss of a single

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	relay or auxiliary relay will not result in relying on time-delayed backup relaying to clear faults, the study of back-up element coordination is not necessary and the completion of a PSCS should not be required. b. Additionally, we believe Requirement 1 should state how many protection system failures must be considered for a PSCS. We believe that only one failure is appropriate for the reasons discussed above. c. PRC-001: The proposed Violation Severity Levels for PRC-001-3 R1 are not commensurate with the draft Measure of the Requirement. The current VSL is ?High? for failure to be ?familiar with the limitations of the protection system schemes applied in its area? and ?Severe? for failure to be ?familiar with the purpose of protection system schemes applied in its area.? The draft Measure states that the applicable entity ?shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel.?The VSLs should be revised to align with the Measure and the ?intent? of the Standard and not effectively split out the purpose of Requirement R1 thus requiring specific documentation for a ?purpose? and a ?limitation?. Exelon suggests the VSLs be revised to the following: Severe: The responsible entity failed to provide evidence that any training evidence exists for basic relaying and any Special Protection Systems within its area. High: The responsible entity failed to provide evidence that all applicable personnel were trained in basic relaying and any Special Protection Systems within its area d. PRC-001: In the Background Section of PRC-027-1 there is a discussion related to PRC-001-1 that was revised as part of Project 2007-03. Specifically, it is stated that in Project 2007-03 SDT retired PRC-001-1 Requirement R2 as because this Requirement addresses data and data requirements that are included in the proposed Reliability Standard TOP-003-2; however, the justification provided in the mapping document associated with Project 2007-03 does not seem to meet the original intent of PRC-001 R2, and does not seem to be a "relocation" of the original requirement (refer to Project 2007-03 Mapping

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	Document Draft 7). PRC-001-1 R2 current revision is as follows:R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible. The Background Section of PRC-027-1 further states that the SPC SDT recommends that Requirement R1 remain in PRC-001-2, until its reliability objective is addressed by either a revision to an existing standard or development of a new Standard. The current revision to PRC-001-2 that removed Requirement R2 was not fully addressed by Project 2007-3 nor voted on by the Ballot Body and therefore Exelon requests that PRC-001-1 R2 be added back in to PRC-001-3 and Project 2007-06, similar to Requirement R1, until its reliability objective by similarly addressed by either a revision or development of a new Standard.

Response: Thank you for your comment.

a. The drafting team contends that the initial PSCS required in Requirement R1, Part 1.1 must be completed to ensure that present coordination exists. If, during that PSCS, the entity can confirm that the coordination is not affected by changes in Fault current, then the entity can apply that technical justification to Requirement R1, Parts 1.1.2 or 1.1.4. The application of redundant Protection Systems does not preclude the necessity of ensuring that your Protection Systems are coordinated.

b. The drafting team does not believe that it should prescribe the details of performing PSCS and leaves that to the engineering judgment of the entities performing the PSCS. No change was made to the standard.

c. In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1.

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	However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the "Effective Date" and "Compliance" sections of the standard is included with this fourth posting of PRC-027-1. d. In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the "Effective Date" and "Compliance" sections of the standard is included with this fourth posting of PRC-027-1.
Essential Power, LLC	a. R3.3 should be limited to Protection Systems associated with Interconnected Elements. b. There is no change needed to the present system:-The TOP is provided with detailed information of GO equipment via PRC-001 and MOD-010, and the TO (being informed of

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	these inputs by the TOP) is then at liberty to modify their Protection Systems if needed. - We periodically request data for available fault current at the interconnect point from the TO, for use in our aux system short circuit studiesChanges in the T&D system otherwise don?t matter to GOs. We do not modify our Protection Systems in response to changes to the Fault current at an interconnecting bus, we just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Everything involving sequencing the tripping of multiple Elements is in the TO?s system. The most that could reasonably be asked of independent GOs is to have a valid Interconnection Service Agreement (ISA), since a coordination study is performed by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so detailed evidence could not be asked of the GO.The SDT states on p.21 of PRC-027 that ?The drafting team has no evidence there is widespread mis-coordination between Owners of Facilities,? and, ?records collected for reliability standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.? This appears to indicate that the present system is working and therefore there is no need to go back to existing unit?s coordination studies to make sure they crossed all of the T?s and dotted all of the I?s according to a standard that retroactively applies requirements that were not in existence at the time of the original coordination studies. c. The purpose statement for PRC-001-3 needs to be changed to match the content of the sole requirement. If this one requirement is to be absorbed by PER-005, consider keeping the purpose and moving the content of PRC-027 back into PRC-001. Please retain one measure per requirement so that the Measurement numbers match the base requirement number. The evidence required for each sub part of each base requirement can be described in the same section as the other sub parts.

Response: Thank you for your comment.

a. The drafting team made the suggested change to Requirement R3, Part R3.3.

b. The standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of

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Protection Systems that affect the reliability of the BES. c. In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the "Effective Date" and "Compliance" sections of the standard is included with this fourth posting of PRC-027-1.	
Associated Electric Cooperative, Inc.	AECI seeks additional clarify of the SDT's intent as to how base PSCS requirements are to be applied within a JRO, and if R1-R2 serves legitimate reliability function, where R1.1.3, & R3-R4 do not apply to intra-JRO interconnected elements because JROs already internally do these; a JRO would still perform R1.1.3 & R3-R4 for interconnected elements with other registered entities; also clarify that R1 would only require one ?master? PSCS for the JRO as opposed to multiple studies for each functional entity within the same JRO.
Response: Thank you for your comment. The Joint Registration Organization (JRO) is responsible for coordinating all of the Protection Systems associated with Interconnecting Elements between the JRO and its neighboring entities (external to the JRO), and between the applicable internal JRO registrations (e.g., Transmission Owner, Generator Owner).	

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ATCO Electric	Can the drafting team draw all timelines in 4 requirements together in a chart to see how these timelines fit together for an entity?
Response: Thank you for your comment. Please reference the Process Flow Chart in the Guidelines and Technical Basis section of the standard as it is a representation of the process, including the relationships between requirements and timeframes.	
DTE Electric	Comments: Different entities that are highly integrated electrically should be using the same short circuit data. If fault data files could be exchanged regularly (bi-annually?) using compatible file formats, short circuit databases wouldn't drift apart (as would occur after five years) and coordination studies could be performed with more confidence. Many settings could require re-visiting when the once every five year fault current update is received. It should be noted that while the emphasis is on BES Interconnected Elements, many other non-BES Interconnected Elements, such as radial distribution transformers, could be affected resulting in a negative impact on the BES.
Response: Thank you for your comment. The drafting team agrees with your comments and believes PRC-027-1 addresses your concerns. While Requirement 2 provides for the 60-month periodic review of Fault currents, Requirement 3 mandates the details of any proposed change(s) or addition(s) at an existing or new Facility associated with the Interconnecting Element (that would modify the conditions used in the coordination of Protection Systems associated with the Interconnecting Element) be provided to the other owner(s) of the Protection Systems associated with Interconnecting Element(s). The drafting team believes the exchanges of information outlined in these requirements will better enable entities to keep short circuit databases aligned. This standard addresses only BES Facilities; however, the established processes could be used for non-BES Facilities as well.	
Texas Reliability Entity	How many buses away from the Interconnect Element does the PSCS need to cover? Figure 5 of the Application Guidelines indicates that only the next adjacent bus is to be included in the PSCS, which implies that the PSCS only covers up to Zone 2. We understand that PRC-027 does not tell any owner how to perform a PSCS or dictate the specific information that is required for a PSCS. It appears from our understanding that the coordination of protective relays beyond the primary zones that affect the

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	interconnected element are the responsibility of the equipment owner, and that it is up to the owner to determine whether these settings are to be shared with other entities for the interconnected element. Please clarify if this understanding is correct.
Response: Thank you for your comment. Your understanding of the equipment owner responsibilities for performing a PSCS in accordance with the draft standard is correct.	
Dynegy	If a Generator Owner does not own a Protection System associated with an Interconnected Element, does the Standard apply? For instance, if the generator breaker opens only for faults on the Generator Owner side of the breaker (i.e., GSU or generator faults). Is it expected most GOs will own Protection Systems associated with an Interconnected Element?
Response: Thank you for your comment. Per the Applicability section, the standard only applies to the Protection Systems owned by a Transmission Owner, Generator Owner, or Distribution Provider that are "installed for the purpose of detecting Faults on Interconnecting Elements of the BES and that require coordination for isolating those faulted Elements". The drafting team does expect that most Generator Owners will own applicable Protection Systems.	
Illinois Municipal Electric Agency	1. Illinois Municipal Electric Agency (IMEA)supports comments under Question 8 submitted by the SERC EC Protection and Control Subcommittee. 2. Also, IMEA requests that Figure 3 be modified or a separate figure be included to clarify guidelines for DP systems that include only non-BES generation. 3. IMEA also requests that Applicability Section 4.2.1 be revised to prevent inconsistency with the FERC-approved interpretation of transmission Protection System as specified in PRC-005-1b. Very specific attention/consideration needs to be given to avoiding unnecessary expansion of applicability to facilities owned by small Distribution Providers; i.e., unnecesarry expansion of scope to protective devices owned by a DP that have no potential adverse impact on the BES. Both FERC and NERC have stated the need to minimize impacts on small entity

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	resources.

Response: Thank you for your comment.

1. Please see the response to the (SERC RRO) comments submitted by the SERC Protection & Control Subcommittee.
2. If a Distribution Provider's system includes only non-BES generation, and the associated Protection Systems are not installed for the purpose of detecting Faults on Interconnecting Elements of the BES, this standard would not apply to coordination of those Protection Systems. Whether or not the generator in Figure 3 is BES or not does not determine the Distribution Provider's applicability to this standard; the determinant is whether or not the associated Protection Systems are installed for the purpose of detecting Faults on Interconnecting Elements of the BES.
3. The term "transmission Protection System", to which the interpretation you reference applies, is not used in the Applicability section or anywhere else in PRC-027-1. Therefore, the draft standard contains no inconsistencies with the FERC-approved interpretation, which was issued to clarify the use of the term in Reliability Standards PRC-005-1b and PRC-004-2a. Per the Applicability section of PRC-027-1, the standard only applies to the Protection Systems owned by a Transmission Owner, Generator Owner, or Distribution Provider that are "…installed for the purpose of detecting Faults on Interconnecting Elements of the BES and that require coordination for isolating those faulted Elements."

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Lincoln Electric System	In consideration that the rationale for Requirement R1 Part 1.1.1 acknowledges that the drafting team has ?no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements?, LES recommends further development of the standard be halted until sufficient technical justification can be provided for the standard?s development. As currently drafted, the drafting team would place excessive documentation requirements on registered entities for activities already being performed as industry best practices. In lieu of turning those best practices into compliance requirements, LES suggests the drafting team leverage existing Reliability Standard PRC-001 as a basis for system protection coordination.

Response: Thank you for your comment.

PRC-027-1 is replacing the requirements of PRC-001 that are associated with actual coordination of Protection Systems necessary for proper performance during faults. In doing so, the drafting team is leveraging PRC-001 as a basis for system protection coordination as well as following the recommendations of the NERC System Protection and Control Task Force (now the System Protection and

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Control Subcommittee – SPCS) in its 2007 *Assessment of Standard PRC-001-0 – System Protection Coordination*, and addressing observations from the Commission in FERC Order 693. The Project 2007-06 – System Protection Coordination drafting team has taken this course after consultation with both NERC and FERC staffs. The drafting team contends that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.	
FirstEnergy Corp	In regard to PRC-027-1: 1. We believe that R3, Part 3.1 is covered in R1, Part 1.2 2. …and propose that R4, part 4.2 be reworded to: 4.2. Prior to implementing any proposed change (s) or modifications associated with Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues In regard to PRC-001-3: 3. The title for PRC-001 "System Protection Coordination" and the purpose statement of this standard is no longer pertinent for the only requirement that remains in the standard - entity familiarity with the purpose and limitations of protection system schemes. This remaining requirement is essentially a training obligation and better suited in a PER standard if deemed necessary for reliability. The drafting team also appears to support this view as discussed in the background statements of the PRC-027-1 standard, however, believes this additional work is outside the scope of its project. However, the PRC-001-3 standard should not be left with a title and purpose statement that will cause industry confusion with PRC-027-1. We suggest that this team adjust PRC-001-3 to include the title ?System Protection Awareness? and a purpose statement of ?To ensure entity understanding of system protection schemes applied to their assets.?FE believes the continuing need for this requirement (PRC-001-3 R1) needs to be carefully considered. NERC standards PRC-023 and PRC-25 address relay loadability limitations. The original blackout report recommendation that

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	drove this requirement appears to now be more thoroughly addressed by those standards. We encourage the NERC Standards Committee to extend the scope of this drafting team?s work through a supplemental SAR to address whether or not PRC-001 can be retired.

Response: Thank you for your comment.

1. Requirement R3, Part 3.1 stipulates that Transmission Owners, Generator Owners, and Distribution Providers with applicable Protection Systems must provide information regarding proposed system changes or additions that may affect the other owner(s) associated with an Interconnecting Element. The objective of this requirement is to enable the process of conducting Protection System Coordination Studies (PSCS). Whereas Requirement R1, Part 1.2, requires Transmission Owners, Generator Owners, and Distribution Providers with applicable Protection Systems to provide a summary of the results of the PSCS after the study has been completed (within 90 calendar days). Therefore, these two requirements are not synonymous.
2. For clarity, the drafting team removed Requirement R4, Part 4.2 and created new Requirement R5, which states: "Each Transmission Owner, Generator Owner, and Distribution Provider that received a response per Requirement R4, shall address any identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element."
3. In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal

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of Requirements R2 and R3, and updated pro forma language for the "Effective Date" and "Compliance" sections of the standard is included with this fourth posting of PRC-027-1.	
Duke Energy	1. In the interest of clarity, Duke Energy feels an example of acceptable evidence for measure 3 of PRC-027-1 R2 would be beneficial. 2. In PRC-027-1, Duke Energy identified a potential gap in Figure 4 of the Application Guidelines. Duke Energy believes that without coordination between the DP and TO, it could lead Transmission Planners and System Protection Engineers to disregard the coordination with protection for the tap line between BES and non-BES equipment. Given the proposed definition of the BES, this scenario could potentially pose a risk to the BES without the proper coordination identified in PRC-027-1.
Response: Thank you for your comment. 1. The drafting team removed the option of performing a technical justification from Requirement R2 and consequently removed the associated Measure M3. 2. Because there are no Protection Systems at Breaker C that protect for Faults on BES Elements, the subject Protection Systems are not applicable under this standard. The drafting team understands the commenter's point; however, this standard only applies to Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements.	
Nebraska Public Power District	My general impression is this standard could be quite a burden to track data for an audit due to the numerous time lines specified that are between entities. My opinion is this will likely result in a difficult to audit standard. This causes concern if we remain in a zero tolerance compliance environment. Consider changing some of the time lines such as 30 and 90 days to 6 months. My general feeling is we should consider other ways to simplify this standard however suggestions I have made have not made it into the draft standard. I recommend more consideration be given to simplification.
Response: Thank you for your comment. A process flowchart is included in the Guidelines and Technical Basis section of the standard to show the relationship between the	

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requirements. The drafting team contends the specific time frames are appropriate and relevant for the reliability-related tasks in each of the requirements. The Rationale boxes for each requirement provide the drafting team's reasoning for the different time frames.	
PJM Interconnection	PJM supports both standards as drafted. Specific to PRC-001-3 R1, PJM urges the SDT to replace the term ?familiar? with language less subjective. There may be a number of interpretations for this term that will result in compliance issues for applicable entities. Suggested revised wording should include language that has a direct tie to the Measure. PJM recommends the following revised requirement for the applicable entities, ?knowledge of the purpose of and limitations of protection system schemes shall be based on the training programs provided.?
Response: Thank you for your comment. In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the "Effective Date" and "Compliance" sections of the standard is included with this fourth posting of PRC-027-1.	
SERC RRO	Please change Figures 3 and 4 so that ?Interconnected Element? is adjacent or points to

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	the line between Breaker C and the point of connection (tap point) on the line between Breakers A and B. It clarifies these examples by having the Figures align with your wording. (The Figures presently imply that the line between Breakers A and B is the ?Interconnected Element?.)The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: Thank you for your comment. The drafting team revised Figures 3 and 4 to indicate the tap line is the Interconnecting Element.	
American Electric Power	1. PRC-001-3: R1 ? The term ?protection system? should be capitalized to match previous versions of this standard. 2. PRC-027-1: Mapping Document ? The verbiage in R1.1 of the mapping document does not match the wording in the proposed standard: ?Protection System Study? is used instead of ?PSCS?. 3. PRC-027-1: Figure 2 ? The phrase ?generator Protection Systems? is often used by Generation Owner relay engineers to mean the Protection Systems installed for the purpose of detecting faults on and protecting the physical generator, which is clearly outside of the scope of this standard. Therefore, AEP recommends changing the verbiage associated with this figure to remove the phrase ?generator Protection Systems? and replace it with a reference to Generator Owner R?s Protection Systems installed for the purpose of detecting faults on the Interconnected Elements. Suggested wording is shown below: Transmission Owner S is to review the Protection System settings associated with Breaker A *and the Interconnected Element* (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, Owner S is to develop proposed Protection System settings associated with Breaker C. Generation Owner R is to review the Protection System settings associated with

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	Breaker C *and the Interconnected Element* (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A. 4. PRC-027-1: R3 & Figure 5 ? As written, R3 will place undue burden on each TO, GO and DP to maintain a list of all other entities connected to each interconnecting bus to which they connect. Furthermore, since the elements are typically owned by the TO, burden will be placed on the TO to respond to requests from other TO?s, GO?s and DP?s as they build their list. R3 and its? associated Figure 5 should be revised such that the responsibility lies with the owner of the Interconnected Element to ensure that relevant information is passed along to each entity who connects to the element when any one entity makes a change.

Response: Thank you for your comment.

1. In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC’s Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the “Effective Date” and “Compliance” sections of the standard is included with this fourth posting of PRC-027-1.

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2. The drafting team made the suggested revision to the mapping document. 3. The drafting team sees no benefit in making the suggested change and believes your issue is addressed by the Applicability section of the standard which specifies the Facilities included in this standard. 4. The drafting team contends that entities making changes or additions to Protection Systems associated with an Interconnecting Element must communicate the proposed changes to the other interconnected owner. As noted in Figure 5, it may be necessary for that other interconnected owner to forward the provided information to the other owners.	
Northeast Power Coordinating Council	1. PRC-027-1 in its entirety needs a quality review. Requirement R2 is not written correctly--it does not refer to the entities first. Also, each Requirement has multiple numbered Measures. 2. The Requirement also states that the functional registration (e.g. GOP) has to demonstrate compliance, not the individual operators. If it is the intent of the Standard that each individual operator of an entity be familiar this should be added. By stating the functional registration as opposed to the individuals, it could be interpreted that as long as any Registered Entity SME is familiar with the purpose and limitations of the protection systems that the entity will be able to demonstrate compliance. Suggested rewording of the Requirement: Each Transmission Operator, Balancing Authority, and Generator Operator responsible for the operation of BES elements shall have its operators be familiar with the purpose and limitations of protection system schemes, either through training or operational experience, applied in its area. There has been a broad variation in how the language of this requirement is applied during audits.
Response: Thank you for your comments. 1. PRC-027-1 has been through numerous quality reviews and meets NERC's guidelines for standards development. 2. In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the	

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	reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the "Effective Date" and "Compliance" sections of the standard is included with this fourth posting of PRC-027-1.
Madison Gas and Electric Company	1. PRC-027-1:The proposed standard contains 30-day and 90-day timing requirements in addition to the 60-month requirement. Please consider revising the 30 calendar day?s provision in requirements R2.2.1, R3.2 and R3.3 to 90 calendar days to avoid possible confusion between different timing requirements in the standard. We do not see a basis on why there needs to be different dates. If all dates were 90 days, it would provide consistancy for entities to follow. 2. In consideration that the rationale for Requirement R1 Part 1.1.1 acknowledges that the drafting team has ?no evidence there is widespread mis-coordination of Protection Systems associated with Interconnected Elements?, LES recommends further development of the standard be halted until sufficient technical justification can be provided for the standard?s development. 3. As currently drafted, the drafting team would place excessive documentation requirements on registered entities for activities already being performed as industry best practices. In lieu of turning those best practices into compliance requirements, NSRF suggests the drafting team leverage existing Reliability Standard PRC-001 as a basis for system protection coordination.

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	4. PRC-001-3: Please consider revising the Purpose of PRC-001-3 to reflect the one remaining requirement. With the updated measure there is an inconsistency between the Purpose, the Requirement, and the Measure. We suggest revising the Purpose to PRC-001, the following: To ensure familiarity with the purpose and limitations of protection systems operated by the entity. Suggest revising Requirement R1 to: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall train its applicable personnel to be familiar with the purpose and limitations of protection systems operated by the entity. The above rewrite now provides a clear and understandable (plus it adds to system reliability) Standard for the applicable entities to follow. The Standard sets a minimum level of training concerning protection systems that entities operate. An entity can always provide training on non-operated protection systems, whereby the entity has determined (based on risk to their system) the scope of training outside the proposed rewrite.

Response: Thank you for your comment.

1. A process flowchart is included in the Guidelines and Technical Basis section of the standard to show the relationship between the requirements. The drafting team contends the specified time frames are relevant and appropriate for each of the requirements. The Rationale boxes for each requirement provide the drafting team's reasoning for the different time frames.
2. The drafting team contends that the draft standard provides a reliability benefit of ensuring that all existing, modified, or new Protection Systems on Interconnecting Elements are coordinated for proper performance during Faults. The drafting team contends that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.
3. PRC-027-1 is replacing the requirements of PRC-001 that are associated with actual coordination of Protection Systems necessary for proper performance during faults. In doing so, the drafting team is leveraging PRC-001 as a basis for system protection coordination as well as following the recommendations of the NERC System Protection and Control Task Force (now the System

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	Protection and Control Subcommittee – SPCS) in its 2007 *Assessment of Standard PRC-001-0 – System Protection Coordination*, and addressing observations from the Commission in FERC Order 693. The Project 2007-06 – System Protection Coordination drafting team has taken this course after consultation with both NERC and FERC staffs. 4. In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the "Effective Date" and "Compliance" sections of the standard is included with this fourth posting of PRC-027-1.
Southwest Power Pool	1. PRC-027-1 As drafted the standard contains 30-day and 90-day timing requirements in addition to the 60-month requirement. Would the drafting team consider making the 30-day and 90-day requirements the same, for example 90 days? This would make staying abreast of timing issues much simpler. 2. Figure 4, Application Guidelines The Note at the bottom of Figure 4 is misleading in that it states that no PSCS is required under this scenario. However, Transmission Owner R is required to have a PSCS for the Interconnected Element between Breakers A and B. The Distribution Provider S is not required to have a PSCS for Breaker C.

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	3. PRC-001-3: Purpose The existing purpose does not fit the single requirement that is left in the standard. We would suggest changing the purpose to the following: To ensure familiarity with system protection schemes utilized within an operating entity?s area. Requirement R1Similarly, the requirement does not match the proposed measure. We suggest modifying the requirement to: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall train its applicable personnel to be familiar with the purpose and limitations of protection system schemes applied in its area.

Response: Thank you for your comment.

1. A process flowchart is included in the Guidelines and Technical Basis section of the standard to show the relationship between the requirements. The drafting team contends the specific time frames are appropriate and relevant for the reliability-related tasks in each of the requirements. The Rationale boxes for each requirement provide the drafting team's reasoning for the different time frames.
2. The drafting team revised Figure 4 to provide additional clarity that the Distribution Provider S depicted does not own a Protection System installed for the purpose of detecting Faults on the Interconnecting Element and is therefore excluded from this standard.
3. In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults –leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's

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	Reliability Standards be consolidated. Because Requirement R1 of PRC-001-2 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the “Effective Date” and “Compliance” sections of the standard is included with this fourth posting of PRC-027-1.
Public Service Enterprise Group	PSEG has the following additional comments: a. To avoid make-work reporting that is detrimental to BES reliability, PSEG recommends that the Applicability section remove Protection Systems, Interconnected Elements, and Protection System components that do not require coordination. Therefore, we propose that the 4.2.1 be modified with this additional language after ?faulted Element?: ?, except for the following Protection Systems, Interconnected Elements, and Protection System components that do not require such coordination:? Protection Systems for the Interconnected Element that are owned by the same functional entity of a single Registered Entity.? An Interconnected Element that is protected by overlapping differential relays only (e.g., a Generator Owner?s GSU that is connected to a Transmission Owner?s bus)? Protection System components for which coordination is unaffected solely due to an increase in Fault current, including:? Transformer differential relays? Line current differential schemes? Generator differential or overall differential, bus differential schemes? Step distance protection schemes? Fault detector settings (these settings are guided directly by PRC-023-X)? Breaker failure settings? Directional Comparison Blocking overcurrent schemes b. ?Application Guidelines? Comments More clarity on what a pre-standard PSCS needs to contain to meet R1.1. Is an e-mail trail from other owners stating that the settings are acceptable? Do calculations need to be shown? c. Language on p. 21: ?The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with Interconnected Elements

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	that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.? If there is no problem, why is this standard being proposed? d. Language on p. 22 that lists examples of Protections Systems where technical justification may be used to exclude the need for a PSCS. Although PSEG has suggested limiting the Applicability in its comments in 8.a, it may be simpler if the standard just listed the Protection Systems that require a PSCS ? that would only be overcurrent elements based upon Fault current. If that scheme is not employed, no PSCS is needed.

Response: Thank you for your comment.

a. The drafting team declines to list the exclusions you suggest, but has revised the Applicability section for clarity as follows:

   4.2 Facilities:

   Protection Systems: a) installed for the purpose of detecting Faults on Interconnecting Elements, and; b) that require coordination for isolating those faulted Elements.

b. The parenthetical phrase in Requirement R1, Part 1.2 provides the clarity you request. "…a summary of the results of each PSCS performed pursuant to Requirement R1, Part 1.1, (including, at a minimum, the Protection System(s) reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed), …."

c. The drafting team contends that the draft standard provides a reliability benefit of ensuring that all existing, modified, or new Protection Systems on Interconnecting Elements are coordinated for proper performance during Faults. The drafting team contends that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.

d. The drafting team declines to list the inclusions you suggest, but has revised the Applicability section for clarity as follows:

   4.2 Facilities:

   Protection Systems: a) installed for the purpose of detecting Faults on Interconnecting Elements, and; b) that require coordination for isolating those faulted Elements.

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ReliabilityFirst	ReliabilityFirst offers the following comments for consideration: 1) Requirement R1, Part 1.2 - ReliabilityFirst recommends converting the parenthetical last sentence ?(including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed)? into four separate and distinct sub-parts. Separating these out will clearly spell out to the applicable entity and compliance auditors the specific items which are required to be provided. Listed below is an example for consideration: 1.2.1 Protection Systems Reviewed 1.2.2 Associated fault currents 1.2.3 Identified issues 1.2.4 Proposed revisions or actions 2) Requirement R2, Part 2.2 - Within both the clean and redline version of the posted draft standard, the equation referenced at the end of Requirement R2, Part 2.2 is inadvertently missing and therefore needs to be added back into the requirement.
Response: Thank you for your comment. 1. The drafting team removed the parenthetical from the requirement. 2. The equation was inadvertently removed during the conversion process required for posting. A new version with the equation was made available on the NERC web site on June 21, 2013.	
Clark Public Utilities	Requirement 3 (and any sub-requirements) should not be applicable to any Interconnection Element owners that are part of the ?same Registered Entity that represents multiple functional entity responsibilities.? Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the same functionally registered entity that developed the details for proposed changes to provide a

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	documentation of those details to all other functionally registered entities. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. Since the definition of Interconnection Elements incorporates the concept of ?Separate Registered Entities and ?Same Registered Entities? it is suggested that the wording be modified to incorporate theses terms as follows: R3. Each Separate Registered Entity and each Same Registered Entity shall provide to each other Separate Registered Entity connected to the same Interconnected Element: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning] 3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnected Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).? New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios? Changes to a transmission system Element that alter any sequence or mutual coupling impedance? Changes to generator unit(s) that result in a change in impedance? Changes to the generator step-up transformer(s) that result in a change in impedance 3.2. Requested information related to the coordination of Protection Systems associated with an Interconnected Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule. 3.3. Within 30 calendar days, details of changes made to Protection

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	Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.

Response: Thank you for your comment.

The drafting team does not agree because there are cases where the Transmission Owner and Generator Owner are part of the same Registered Entity but separate technical groups are involved in performing the required Protection System Coordination Studies. For the case where one registered entity representing multiple functional entities with the same protection group doing all the coordination, the drafting team included the following note: “In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS would be sufficient for use by all entities.”

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City of Tacoma	Tacoma Power appreciates the efforts of the SDT. This is a difficult process and topic on which to standardize. 1. It would help, especially for the Flowchart, if R1.1.3 could be separated into a revised R1.1.3 ?according to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1; or technically justify why such a study is not required? and a new R1.1.4 ?within six calendar months of being notified of a change as described in Requirement R3, Part 3.3; or technically justify why such a study is not required.? 2. In R3.1, the language ?or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s)? appears to be very open-ended with respect to the second, third, and fourth bullets under R3.1. In theory, any impedance change within an entity?s system could qualify, which brings into question potential overlap between R2 to address incremental changes and R3.1. R3.1 should establish a brighter line for what triggers an entity to begin coordination activities for proposed impedance changes not at an existing or new Facility associated with the Interconnected Element. In other words, at what point is an impedance change considered an incremental change and, therefore, applicable to R2, as

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	opposed to R3.1? 3. In the Flowchart, the arrows are confusing above the decision diamond ?(R1.1.3) Is a new PSCS required?? 4. Referring to M2, M5, M7, and M8, is any confirmation of receipt required in order to demonstrate that a responsible entity ?provided? the information? It is recommended that evidence of receipt not be required to demonstrate that an entity ?provided? information applicable to these measurements. 5. Referring to the Application Guidelines, Figure 5 and associated discussion, the introductory paragraph statement ?in Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be check for coordination with Generator Owner T? appears to contradict the discussion on page 39 of 40 of the redlined copy of PRC-27-1.

Response: Thank you for your comment.

1. The drafting team made the suggested change.
2. Requirement R2 addresses periodically performing Fault current studies, using an entity's short circuit model to maintain awareness of Fault current changes (not incremental impedance changes) that could affect proper performance of Protection Systems. Requirement R3 addresses communication of physical changes or additions, such as those that alter impedance values, so entities can keep their Protection System databases and short-circuit models up-to-date for the performance of accurate Protection System Coordination Studies.
3. The drafting team revised the flowchart to provide clarity.
4. The requirements mandate that entities provide information. The measures complement the requirements in suggesting evidence that is appropriate or acceptable to satisfy compliance with the requirement. The measures state that acceptable evidence is documentation demonstrating that the information was provided within the specified timeframe. No confirmation of receipt is required as evidence.
5. Although Transmission Owner S has no Protection Systems located at Station 1, Owner S does have other Protection Systems that require coordination with the Generator Owner; therefore, the language is not contradictory.

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Idaho Power Co.	Thank you for the opportunity to comment. While we are in favor of this version, we seek clarification on one item. Requirement R2 states that the fault values used in determining the 10% change will be measured at the ?interconnecting bus?. While reviewing the examples in the application guideline section, two ?interconnecting bus? are labeled in Figure 1, 3, and 4. If the coordination concern is related to the interconnecting element, it would seem reasonable that the ?interconnecting bus? for Owner S to place faults on to determine the 10% change is that at Station 1/Transmission owner R, looking at figure 1. This would capture the change in fault current seen by the Owner S Protection System on breaker E. Placing faults on the interconnecting bus behind breaker E if I am owner S does not seem appropriate when considering coordination on the interconnecting element.
Response: Thank you for your comment. In reference to Figure 1, the intent is for each Transmission Owner to check for changes in Fault current at its own interconnecting bus; if either owner identifies a 10% change, it would notify the other owner pursuant to Requirement R2, Part 2.2.1.	
CenterPoint Energy	The draft for PRC-027-1 states: ?records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.? CenterPoint Energy considers the proposed requirements to be too prescriptive for Protection System coordination when it has not been identified as a reliability issue and expects such requirements would provide little, if any, reliability benefits. We believe the majority of existing Interconnected Facilities have time-proven and fault-proven Protection System set points and that newer facilities, including replacement relay panels, are commissioned utilizing appropriate coordination studies that include necessary interaction between interconnected entities. CenterPoint Energy recommends reevaluating the need for this standard with consideration that this subject area could instead be addressed by continuing to focus on misoperation analysis and through best practices initiatives.
Response: Thank you for your comment.	

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The drafting team contends that the draft standard provides a reliability benefit of ensuring that all existing, modified, or new Protection Systems on Interconnecting Elements are coordinated for proper performance during Faults. Further, it should be noted that existing standard PRC-001-1 currently requires coordination of protection systems for new facilities and those associated with changes to existing facilities. PRC-027-1 clarifies the intent of the requirements of PRC-001 related to coordination and correcting the applicability to the equipment owners. The drafting team contends that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.	
California ISO	The ISO feels that a requirement should be added for the TO, GO or DP to notify their TOP and PC when a new or revised Remedial Action Scheme or Special Protection System is implemented.
Response: Thank you for your comment. The drafting team believes this is outside the scope of PRC-027-1. A NERC project to revise the PRC standards regarding SPSs is included in the most recent Reliability Standards Development Plan.	
SMUD	The timing provided in R3.1 is contains no specification that correlate to the timing requirements of the other R3 subrequirements .
Response: Thank you for your comment. The drafting team believes that specifying a single time frame for Requirement R3, Part 3.1 is not appropriate for the wide variety of conditions that will need to be evaluated.	
Tri-State G &T	Tri-State is concerned about the timeframes allowed in Requirement R1, associated with Requirement 3, Part 3.1, especially when the proposed change does not affect the conditions used in the coordination of Protection Systems. The way we read Requirement R3, Part 3.1, a planned relay replacement will have to go through the PSCS process or a technical justification would be required even if it does not affect coordination of other Protection Systems. We would propose that Part 3.1 be changed as follows: 3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnected Element if the proposed

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	change requires a change in the coordination of Protection Systems associated with the Interconnected Element(s); or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).
Response: Thank you for your comment. The drafting team contends changes associated with the bulleted list in Requirement R3, Part 3.1 must be communicated to the other owners associated with an Interconnecting Element so each owner can: verify the changes do not affect their Protection Systems; and, keep their Protection System databases and models up-to-date.	
ITC	1. We vote to reject Draft 3 of PRC-027-1 primarily due to enormous increase in administrative burden with no appreciable gain in system reliability. We agree with SDT there is reliability benefit to performing these tasks. However, as the SDT members stated at presentations to RFC Protection Subcommittee and to NATF Workshop, utilities are already doing this work. The SDT?s own rationale states ?no evidence there is widespread miscoordination of Protection Systems?. Therefore, the only outcome of this standard is that utilities will greatly increase administrative burden to become auditable. 2. Figure 4 exclusion of PSCS on the Interconnected Element is not found in standard. Figure 4 states the line or tap is the Interconnected Element, therefore TO owns ?facilities? and must meet R1-R4. Either definition of Interconnected Element must be revised to exclude Figure 4 example, or Figure 4 must be corrected to show TO is still responsible for R1-R4. 3. Example Figures 1-5 create responsibilities on owners to ?propose? and ?review for coordination? which are not found in the standard. Either these responsibilities should be removed from Figures or the responsibilities should be added to the standard. 4. The last sentence in Figure 5 specifies the TO will provide GO settings to the other TO. This contradicts R3 which states, ?Each TO, GO, and DP shall provide to each

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	TO, GO, and DP?? Again, the Figures are creating responsibilities not found in the standard. 5. The purpose of Applicability section 4.2 Facilities is unclear. Each requirement deals with requirements around the Interconnected Elements. If the purpose of section 4.2 is to try and exclude DP relays which do not purposefuly trip for BES faults, this should be more clearly stated. This exclusion should be moved to Interconnected Element definition and section 4.2 rewritten to target Interconnected Elements. Or section 4.2 should be the corrected Interconnected Element definition, and there will be no need for a new definition in this standard. 6. Example Figure 2 creates different responsibilities for GO than Figure 3 does for DP. Why the difference? Essentially they are the same: both have protection systems which trip for faults on Interconnected Element. Again, the Figures are creating responsibilities not found in the standard.

Response: Thank you for your comment.

1. The drafting team contends that the draft standard provides a reliability benefit of ensuring that all existing, modified, or new Protection Systems on Interconnecting Elements are coordinated for proper performance during Faults. The drafting team contends that this standard is necessary to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES.
2. The drafting team modified Figure 4 to address your concern.
3. The Figures included in the standard are designed to provide examples of how to apply the requirements of PRC-027-1. Requirements associated with the proposal and review of Protection System design and settings can be found in Requirements R3 and R4, respectively. However, the drafting team modified the language in the figures to address your concern.
4. The drafting team believes the responsibilities described in the example you cite are consistent with the requirements of the standard. In the example (Transmission Owner R) will have settings provided from Generator Owner R, through its obligation under Requirement R3, and will in turn be required by Requirement R3, to provide these settings to Transmission Owner T so a

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	PSCS can be performed. 5. The drafting team revised the Applicability section to remove 4.2.1. 6. Figure 2 represents a BES generator connected to a BES transmission station where the Generator Owner has Protection Systems associated with breaker A that operate for Faults on the Interconnecting Element. The drafting team believes the responsibilities outlined in Figure 2 for the equipment owners are consistent with the requirements of PRC-027-1. Figure 3 represents a generator (or network system) that is not connected to, or part of, the BES. However, in this figure, the Distribution Provider S does have a Protection System at the facility that is "…installed for the purpose of detecting Faults on Interconnecting Elements of the BES" (which trips breaker C) and, therefore, coordination of that Protection System is required by PRC-027-1. The drafting team believes the responsibilities outlined in Figure 3 for the equipment owners are consistent with the requirements of PRC-027-1.

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Draft 1 of SAR posted for comment June 11, 2007 – July 10, 2007.
2. SAR approved on August 13, 2007.
3. First posting of revised standard PRC-001-2 on September 11, 2009.
4. Transitioned from a revision of PRC-001-1 to development of PRC-027-1 based on industry comments, Quality Review feedback, and consideration of FERC directives relative to the existing requirements of PRC-001-1.
5. Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012.
6. Draft 2 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from November 16 – December 17, 2012.
7. Draft 3 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from June 4 – July 3, 2013.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1,with the stated purpose ‘to coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.’ This standard incorporates and clarifies the coordination aspects of Requirements R2 and R3 from PRC-001-2 (formerly R3 and R4 of PRC-001-1). The SPCSDT is requesting a posting for stakeholder comments for a 45-day formal comment period and ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Ballot	September - November 2013
Final Ballot	December 2013
BOT Adoption	February 2014

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2007-06 – PRC-027-1	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here.

The following terms are defined for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

Interconnecting Element: A BES Element that electrically joins Facilities:
a) owned by separate Registered Entities, or
b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Transmission Owner, Generator Owner, or Distribution Provider).

Protection System Coordination Study: A study that documents existing or proposed Protection Systems operate in the intended sequence for clearing Faults.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Coordination for Performance During Faults**
2. **Number:** PRC-027-1
3. **Purpose:** To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider (that own Protection Systems identified in the Facilities section 4.2 below)

4.2 **Facilities:**

Protection Systems:

a) installed for the purpose of detecting Faults on Interconnecting Elements, and

b) that require coordination for isolating those faulted Elements

5. **Background:**

On December 7, 2006, the NERC Planning Committee approved the assessment of Reliability Standard PRC-001 – System Protection Coordination, prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF noted problems with the applicability to entities and vagueness of requirements in the existing PRC-001-1 reliability standard. The SPCTF concluded that the deficiencies of Reliability Standard PRC-001-1 were magnified by having requirements that addressed coordination of protection functions and capabilities in the operating and planning timeframes. Consequently, the SPCTF recommended that the requirements for the operating horizon and planning horizon be clearly delineated, and possibly divided into two standards.

The NERC Standards Committee approved a Standard Authorization Request that included the modifications noted by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPCSDT) posted an initial draft of Reliability Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPCSDT attempted to address all issues identified by the SPCTF assessment of PRC-001-1. The SPCSDT responded to the comments from the initial posting of PRC-001-2, and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC Quality Review (QR) in December 2010. Based on the results from the QR, and after informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to follow the SPCTF recommendation and focused their knowledge and expertise on developing a new results-based standard, concentrating on the reliability aspects (the coordination of new and existing protective systems in the planning horizon) associated with Requirements R3 and R4 of PRC-001-1. These aspects of coordination are incorporated and clarified in the proposed Reliability Standard PRC-027-1 – Protection System Coordination for Performance During Faults with the stated purpose:

> *"To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults."*

PRC-001-1 contained a non-specific training requirement (Requirement R1), three operating time frame requirements (Requirements R2, R5 and R6), and two planning requirements (Requirements R3 and R4). The SPCSDT transferred the responsibility of addressing the operating Requirements R2, R5, and R6 to the drafting team for Project 2007-03 Real-time Operations, charged with revising the TOP group of reliability standards. The Project 2007-03 drafting team retired Requirements R2, R5, and R6 of PRC-001-1 because they addressed data and data requirements that are now included in Reliability Standard TOP-003-2. The NERC Board of Trustees adopted Reliability Standards TOP-003-2 and PRC-001-2 on May 9, 2012.

The SPCSDT posted Draft 3 of PRC-027 in June, 2013 for comment and ballot. As part of that posting, the drafting team proposed revisions to PRC-001-2. The revisions were being proposed as an interim step to provide clarity to PRC-001 until it is retired. However, since this last posting, the informal initiative for revising PER-005-1 has transitioned to a formal project, Project 2010-01 Training. The proposed revisions to PER-005-1 address the reliability objective of PRC-001-2, Requirement 1. Proposed Reliability Standard PRC-027-1 incorporates the aspects of coordination in Requirements R2 and R3 of PRC-001-2. Consequently, NERC staff and the SPCSDT are recommending the retirement of PRC-001-2. As such the drafting team is no longer considering changes to PRC-001-2. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for stakeholder review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.

Other Aspects of Coordination of Protection Systems Addressed by Other Projects:

Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects:

- Underfrequency Load shedding programs are addressed in PRC-006-1. Generator performance during frequency excursions is being addressed in PRC-024-1 by Project 2007-09 Generator Verification.
- Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed in PRC-024-1 by Project 2007-09, Generator Verification.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-1 by Project 2007-09, Generator Verification.

- Transmission relay loadability is addressed in PRC-023-2.
- Generator relay loadability is addressed in PRC-025-1 by Project 2010-13.2, Phase 2 of Relay Loadability: Generation.
- Protective relay response during power swings will be addressed by Project 2010-13.3, Phase 3 of Relay Loadability: Stable Power Swings.
- Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and are addressed in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

The SPC SDT believes that including these other aspects of protection coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

B. Requirements and Measures

Rationale for R1:

Part 1.1 A Protection System Coordination Study (PSCS) is necessary to verify coordination of Protection Systems for existing and new Interconnecting Elements. The drafting team defines the term "Interconnecting Element" as "A BES Element that electrically joins Facilities: a) owned by separate Registered Entities, or b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner)."

Part 1.1.1 The drafting team believes 60 calendar months is an appropriate period of time for entities to perform the PSCS required where no study exists. The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnecting Elements that warrants a shorter time frame.

Part 1.1.2 The drafting team believes that 12 calendar months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater Fault current change at an interconnecting bus, where such conditions may warrant a new PSCS, or to technically justify why no such study is required. Refer to the Application Guidelines for Requirement R1 for examples of Protection Systems where technical justifications may be used.

Part 1.1.3 The drafting team believes that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, Part 3.1, or to technically justify why no such study is needed. The drafting team believes the timeframe associated with the requirement for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies is unnecessary because notification of such a change may occur weeks or years prior to the change. The initiating entity has the incentive to provide the identified information as soon as possible to ensure timely implementations.

Part 1.1.4 The drafting team believes that entities must perform the studies required when notified of changes identified in Requirement R3, Part 3.3, or to technically justify why no such study is needed. The drafting team believes that six months is an appropriate period of time for entities to perform the studies required or to technically justify why no such study is needed when details of changes are provided associated with Requirement R3 Part 3.3.

Part 1.2 The drafting team believes to properly ensure coordination of Protection Systems associated with Interconnecting Element(s), all entities need to share the summary of results of a PSCS and assess the study results. The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS performed in accordance with Requirement R1, Part 1.1 to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s).

Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

1.1. Perform a Protection System Coordination Study (PSCS) for each of its Interconnecting Elements as follows:

1.1.1 Within 60 calendar months after the effective date of this standard, if no PSCS for that Interconnecting Element exists.

1.1.2 Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required.

1.1.3 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or technically justify why such a study is not required.

1.1.4 Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3, or technically justify why such a study is not required.

1.2. Within 90 calendar days after the completion of each PSCS or the technical justification pursuant to Requirement R1, Part 1.1, provide to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s): a summary of the results of each PSCS performed, including, at a minimum, the Protection Systems reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed; or the technical justification.

M1. Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1, 1.1.2, 1.1.3, and 1.1.4 is a dated PSCS, or the summary of the results of each PSCS (hard copy or electronic file formats) demonstrating the time frames specified or agreed to in Parts 1.1.1, 1.1.2, 1.1.3, and 1.1.4 were achieved. Acceptable evidence of a technical justification for not performing a PSCS as specified in Parts 1.1.2, 1.1.3, and 1.1.4 may include, but is not limited to, documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any aspect of coordination.

M2. Acceptable evidence for Requirement R1, Part 1.2 is dated documentation demonstrating that the summary of the results of each PSCS or the technical justification (hard copy or electronic file formats) were provided within the specified time frame to the owner(s) of the Protection System(s) associated with the Interconnecting Element(s).

Rationale for R2: This requires a periodic review of Fault currents at the interconnecting bus and providing the results to the applicable entities when changes occur that meet the criteria of Requirement R2. It is important that interconnecting Facility owners are kept aware of changes that could affect proper performance of their Protection Systems. The Transmission Owner is identified as the entity responsible for performing the short circuit studies because they maintain the data necessary to perform the studies. Note: short circuit studies are used to determine the Fault current values at the interconnecting bus where a PSCS exists. These studies are typically performed assuming maximum generation and all Facilities in service.

The drafting team believes 60 calendar months provides the entities flexibility to schedule and perform the activities specified in Requirement R2, Parts 2.1 and 2.2.

Part 2.1 The drafting team believes maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus are necessary quantities needed to review the coordination.

Part 2.2 The drafting team is including this equation to assure a consistent approach is used by each Transmission Owner when calculating the percent change in Fault current values.

Part 2.2.1 The drafting team believes the 30-calendar day time frame is reasonable for providing the Fault current information to the owner(s) of the Protection System(s) associated with the Interconnecting Element. The drafting team determined that a change in Fault current of 10% indicates an appropriate point at which to provide this information, based on the fact that Protection Systems are typically set with margins above 10%.

R2. For each Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

2.1. Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at its interconnecting bus(s) where a PSCS is available pursuant to Requirement R1.

2.2. Calculate the percent change between the Fault current values (single line to ground and 3-phase for its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation:

$$\%\,Change = \left|\frac{Iscs - Ipscs}{Ipscs}\right| x\ 100$$

Where: I_{scs} = Fault current value from present short circuit study

And: I_{pscs} = Fault current value used in the most recent PSCS

2.2.1 Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (I_{scs}) to each owner of the Protection System(s) associated with the Interconnecting Element(s).

M3. Acceptable evidence for Requirement R2, Parts 2.1 and 2.2 is dated documentation (hard copy or electronic file formats) that contains the present Fault current values from the short circuit study for each interconnecting bus analyzed, and identifies the percent change from the Fault current values used in the most recent PSCS determined by the equation.

M4. Acceptable evidence for Requirement R2, Part 2.2.1 is dated documentation (hard copy or electronic file formats) that the updated Fault current values (I_{scs}), were provided within the specified timeframe to each owner of the Protection System associated with the Interconnecting Element.

Rationale for R3: This requires the transfer of appropriate information to the entities associated with each Interconnecting Element due to circumstances identified in Parts 3.1, 3.2, and 3.3.

Part 3.1 The reliability objective of this requirement is to enable the process of conducting PSCSs by ensuring that the information is provided to the owner(s) of the Protection Systems associated with Interconnecting Element(s). The drafting team believes that information about any proposed change or addition (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the Interconnecting Element. The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list provided in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. Examples of changes to generator units that result in impedance changes could include replacements and re-ratings. This requirement also pertains to changes identified as a result of studies performed in Requirement 1, Part 1.1.

Part 3.2 The purpose of this requirement is to provide a means for an entity to receive the requested information in a timely manner in order to perform a PSCS, as required in Requirement 1, Parts 1.1.1, 1.1.2, 1.1.3, and 1.1.4. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide this information. The requirement also provides some flexibility for the parties involved to determine an otherwise agreed-to schedule, if appropriate.

Part 3.3 The drafting team believes 30 calendar days is sufficient time to provide the information.

Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that describes the information listed in Requirement R3, Parts 3.1 and 3.3 below is sufficient for use by all entities.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnecting Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s).

- New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios
- Changes to a transmission system Element that alter any sequence or mutual coupling impedance
- Changes to generator unit(s) that result in a change in impedance
- Changes to the generator step-up transformer(s) that result in a change in impedance

3.2. Requested information related to the coordination of Protection Systems associated with an Interconnecting Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule.

3.3. Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.

M5. Acceptable evidence for Requirement R3, Part 3.1 may include, but is not limited to, documentation (hard copy or electronic file formats) demonstrating that a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) as identified in the bulleted list, was provided to each responsible entity connected to the same Interconnecting Element.

M6. Acceptable evidence for Requirement R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was provided according to the agreed-upon schedule, or within 30 calendar days absent such an agreement.

M7. Acceptable evidence for Requirement R3, Part 3.3 is dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the permanent changes made was provided within 30 calendar days.

Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with Interconnecting Elements confirm that the Protection System(s) applied were reviewed and a response was provided to the other owner(s). The review assures that the owners of Protection Systems associated with the affected Interconnecting Element are aware of the changes and have responded with comments if necessary.

The drafting team believes 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with Interconnecting Elements to review the summary results of a PSCS or the technical justification and respond. Note: Pursuant to Requirement R1, Part 1.2, at a minimum, the summary of the results of a PSCS must include the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. The response should indicate the results of the PSCS or the technical justification were reviewed and, if applicable, any identified issues.

Note: The drafting team recognizes there could be situations where one owner may not agree with the other owner's protection philosophy but they can confirm that there were no identified coordination issues.

Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that describes the information listed in Requirement R3, Parts 3.1 and 3.3 below is sufficient for use by all entities.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that received a summary of the results of a PSCS or a technical justification explaining why a PSCS is not required (pursuant to Requirement R1, Part 1.2) shall, within 90 calendar days after receipt or according to an agreed upon schedule, review the summary of the results or the technical justification, and respond to the other owner(s) either: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Confirming that the summary of the results was reviewed and no coordination issues were identified, or
- Confirming that the summary of the results was reviewed and any identified coordination issue(s) were noted, or

- Confirming that a technical justification was reviewed and no issue(s) were identified, or
- Confirming that a technical justification was reviewed and any identified issue(s) were noted

M8. Acceptable evidence for Requirement R4 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement.

Rationale for R5: This requirement ensures owner(s) of Protection System(s) associated with Interconnecting Elements have communicated and addressed any identified coordination issues prior to implementing changes in the Protection System(s) (i.e., the in-service date of the Protection System(s)).

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that received a response pursuant to Requirement R4 shall address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

M9. Acceptable evidence for Requirement R5 is dated documentation (hardcopy or electronic file formats) demonstrating that a response pursuant to Requirement R4 was received and that any identified coordination issues were addressed prior to implementation of any proposed Protection System(s) changes or additions.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System associated with an Interconnecting Element shall each keep data or evidence to show compliance with Requirements R1, R2, R3, R4, and R5, and Measures M1 through M9, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner or Distribution Provider that owns a Protection System at a Facility associated with an Interconnecting Element is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by less than or equal to 10	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to 20	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required but was late by more than 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar days.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			calendar days.	calendar days.	calendar days.	OR The responsible entity failed to perform a Protection System Coordination Study on an Interconnecting Element in accordance with Requirement R1, Parts 1.1.1, 1.1.2, 1.1.3, or 1.1.4. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2, 1.1.3, or 1.1.4. OR The responsible entity failed to provide a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2.
R2	Operations Planning, Long-term Planning	Medium	The Transmission Owner performed a short circuit study, as required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days.	The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 90 calendar days. OR The Transmission Owner

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	failed to perform a short circuit study, as required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent change between the Fault currents, according to the equation designated in Requirement R2, Part 2.2. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnecting Element, the updated Fault current values, as required in Requirement R2, Part 2.2.1.
R3	Operations Planning, Long-term Planning	Medium				The responsible entity failed to provide the owner(s) of the Facility associated with the Interconnecting Element, details for any proposed

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	change or addition identified in Requirement R3, Part 3.1. OR The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the information required in Requirement R3, Part 3.3.
R4	Operations Planning, Long-term Planning	Medium	The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following receipt of the Protection System Coordination Study summary of the results or technical	The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following receipt of the Protection System Coordination Study summary of the results or technical	The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following receipt of the Protection System Coordination Study summary of the results or technical	The responsible entity responded in more than 120 calendar days following receipt of the Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			justification, as required in Requirement R4.	justification, as required in Requirement R4.	justification, as required in Requirement R4.	OR The responsible entity failed to review the Protection System Coordination Study summary of the results or the technical justification provided to them in accordance with Requirement R4. OR The responsible entity failed to respond to the other owners(s) in accordance with Requirement R4.
R5	Operations Planning, Long-term Planning	Medium				The responsible entity failed to address any identified coordination issue(s), prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) in accordance with Requirement R5.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Purpose:

To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.

This standard requires that separate Registered Entities communicate with each other to coordinate Protection System components on existing Interconnecting Elements; and communicate with each other prior to the energization of new or modified Protection Systems associated with Interconnecting Elements. The goal of the coordination is to verify that the Protection Systems intended for sensing Faults will operate in the intended sequence for internal and external Faults on the Interconnecting Element.

Requirement R1:

This requirement directs the applicable entities to perform a Protection System Coordination Study (PSCS) for every Interconnecting Element to verify coordination of existing Protection Systems where no recent study exists; or when Facility configuration changes are made, or where Fault current changes of 10% or more have occurred. In developing the language to define a PSCS, the System Protection Coordination Standard Drafting Team (SPC SDT) considered various reference books discussing protective relaying theory and application, along with the following description of "coordination of protection" from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Using the reference material cited above as guidance, the drafting team defined the term Protection System Coordination Study (PSCS) for use within the PRC-027-1 Reliability Standard as:

> "A study that documents existing or proposed Protection Systems operate in the intended sequence for clearing Faults."

PSCSs comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in PSCSs include maximum generation with the transmission system under normal operating conditions and under single contingency conditions. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), and adequate directional polarizing quantities.

Part 1.1.1:

The drafting team believes applicable entities should have a documented PSCS for each Interconnecting Element to validate the Protection Systems associated with those Interconnecting Elements perform in a manner consistent with the purpose of this Standard. Additionally, the drafting team believes that 60 calendar months is an appropriate amount of time for entities to perform the initial studies expected under this requirement. This period considers the time some entities may require to create project scopes, acquire proposals, and secure contracts to hire external resources that may be needed to perform the studies. The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with Interconnecting Elements that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.

Part 1.1.2:

After notification of an identified 10% or greater change in Fault current (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1), the notified entities must perform a new PSCS of the Interconnecting Element or document why a study is not required. The drafting team recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater change in Fault current may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the 12-calendar month time frame associated with this requirement represents a reasonable period to perform the studies that are required after identification by the 60-calendar month Fault current review.

Part 1.1.3:

After proposing or being notified of a change at a Facility associated with the Interconnecting Element, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the proposed or notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the timeframe associated with performing a PSCS for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3, Part 3.1 is unnecessary because notification of such a change may occur weeks or years prior to the change due to the wide variety of conditions that may be associated with a particular change. The drafting team sees the entity initiating any change as having the incentive to move this along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R5.

Part 1.1.4:

After being notified of a change at a Facility associated with the Interconnecting Element associated with Requirement R3, Part 3.3, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes that six calendar months is an appropriate period of time for entities to perform the studies required, or to technically justify why no such study is needed.

Examples of Protection Systems where technical justifications may be used include:

1. Differential elements
2. Distance elements where infeed is not used in determining reach for the protection scheme.
3. Supervised overcurrent elements enabled by:
    - Loss of potential condition
    - Some communication assisted tripping
    - Switch-Onto-Fault (SOTF)
4. Reverse power, definite time &/or time overcurrent elements:
    - Designed to coordinate during maximum generation with the transmission system under normal operating conditions and under single contingency conditions regardless of Fault current.
    - Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.).

Requirement R1, Part 1.2 directs the entity performing the PSCS to provide a summary of the study results or a technical justification to the affected Interconnecting Element owner(s). The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS it performed to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s). (Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that meets the requirements for a summary of the results of the PSCS would be sufficient for use by both Registered Entities.) The following inputs and results of a PSCS must be included in the summary provided pursuant to this requirement:

1. A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Facility, and which were reviewed for coordination of protective relays as part of the study, including the contingencies used in the evaluation.
2. A listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Facility under study.
3. A listing of any issues associated with the relay settings of the other owner(s) at the Facility that were identified by the study.
4. Any proposed revisions to a Protection System or its protective relay settings that were identified by the study.

Requirement R2:

The drafting team investigated various inputs that would trigger a review of the existing PSCSs and determined, through the experience of the drafting team members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated PSCS may be necessary. These variations could result from the accumulation of incremental changes over time. This requirement mandates the Transmission Owner perform a periodic review of Fault currents.

The short circuit study provides the Fault current values used to calculate the percent change between the most recent PSCS and the present Fault current values indicated by the short circuit study performed pursuant to Requirement R2, Part 2.1. This calculation is necessary to identify Fault current changes that must be communicated in accordance with Requirement R2, Part 2.2. Short circuit studies are typically performed assuming maximum generation and all Facilities in service.

The drafting team believes that 60 calendar months is an appropriate interval for reviewing Fault currents. The drafting team believes studies associated with changes that would affect the coordination in less than 60 calendar months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.2.1 further directs the Transmission Owner to, within 30 calendar days, inform each owner of the Facility associated with the Interconnecting Element when short circuit studies indicate that 10% changes in Fault current have occurred at the interconnecting bus(s). The drafting team believes the 30-calendar day time frame associated with this requirement is reasonable for providing the Fault current information to the interconnecting entity(s) and is consistent with other NERC reliability standards.

In Requirement R2, the Transmission Owner is identified as the functional entity responsible for performing the short circuit studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.

Requirement R3:

This directs the registered functional entity initiating any proposed change or addition to provide the details to the other affected entities of the Interconnecting Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes. Documentation provided to these other owners may include, but is not limited to, power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings. The recipient will incorporate the applicable information into its PSCSs to evaluate whether changes are required.

The list of applicable changes provided in Requirement R3, Part 3.1 is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. The drafting team recognizes that Facility changes at other locations can impact the PSCS of the Facility associated with the Interconnecting Element; e.g., the addition of a large autotransformer bank or generator not directly connected to the Interconnecting Element. The drafting team believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the drafting team sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule.

Requirement R3, Part 3.2 allows for entities to agree upon a schedule, appropriate to the circumstances, for providing the details needed to conduct a PSCS or, absent such agreement, within 30 calendar days of a request for this information. This requirement provides a means for entities to receive requested information in a timely manner. In consideration of circumstances where the information may not be readily available or may be incomplete due the retirement of personnel, the purging of records, change of ownership, etc., it also provides the flexibility of mutually agreeing to a schedule for exchanging information. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide the requested information where no other agreement exists.

Requirement R3, Part 3.3 includes a provision for providing details associated with changes to the previously agreed-upon coordination when permanent changes are made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components. Based upon the limited number of instances that would occur under such circumstances, the drafting team believes 30 calendar days after determining that changes are required is an appropriate time frame for providing the associated details to affected entities.

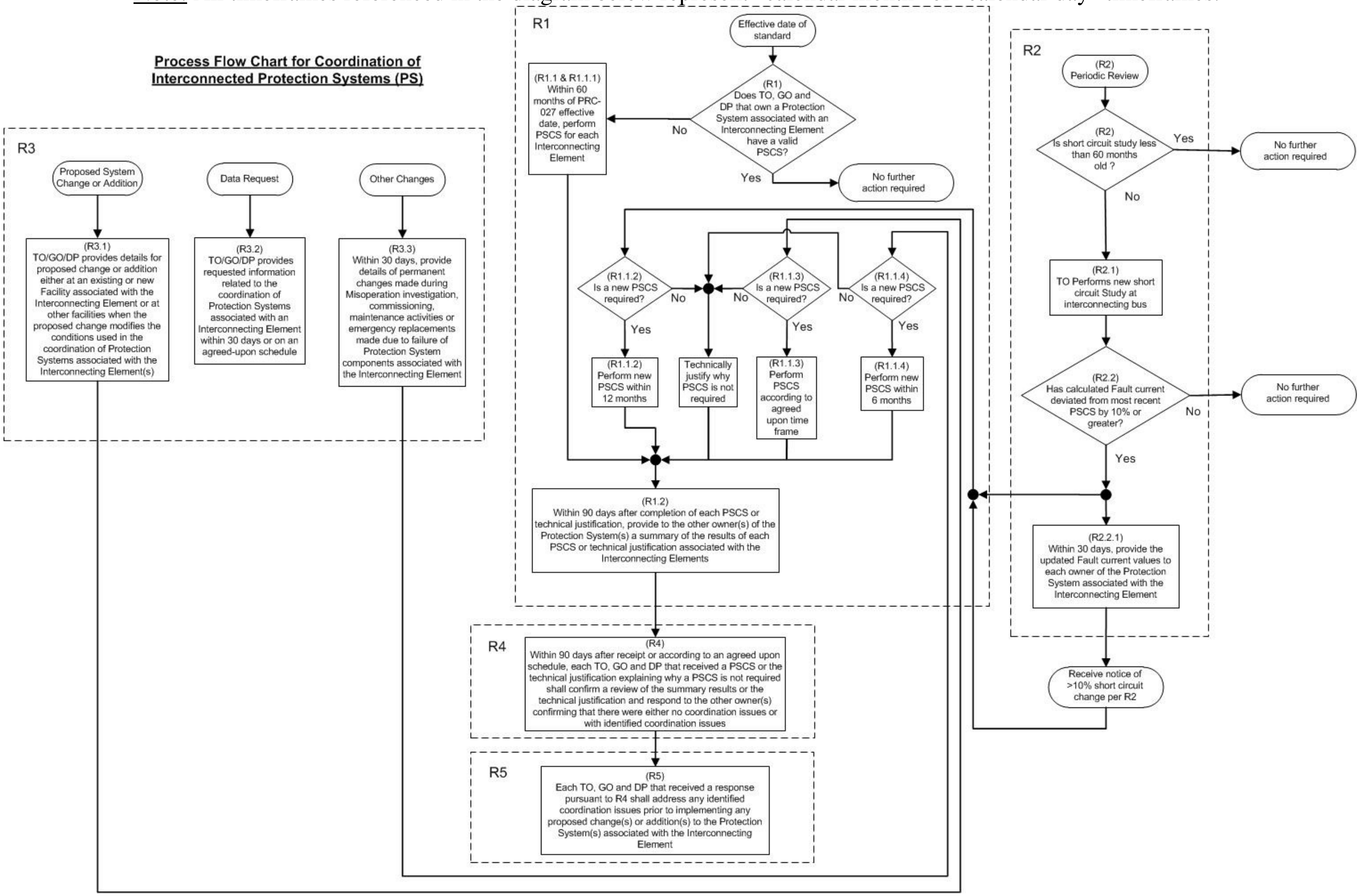
Requirement R4:

Requirement R4directs applicable entities, within 90 calendar days after receipt, to review the summary results of a PSCS or the technical justification, as described in Requirement R1, Part 1.2; and respond that they have reviewed and identified any issues. The drafting team believes 90 calendar days after receipt provides a reasonable time for the owners of Facilities to review.

Requirement R5:

The reliability objective of this requirement is to bring the process of Protection System coordination full circle by ensuring owners of Protection System(s) associated with Interconnecting Elements have communicated and addressed any identified coordination issues prior to implementing changes in the Protection System(s) (in-service date).

Process Flow Chart: Below is a complete representation of the process, including the relationships between requirements:
Note: All timeframes referenced in the diagram below represent "calendar month" or "calendar day" timeframes.



Example Process

An example of the interaction between entities required to gather the information to perform an accurate study is provided below. This example is given as general guidance only and is not intended to represent all situations that may occur. More detailed examples are provided along with Figures 1-5 in the section that follows this example.

- The initiating entity (Entity A) will contact the interconnecting entity (Entity B) and provide details of the change(s) and may also request up-to-date Protection System information.
- Entities A and B will determine whether a new PSCS is required. In this example both agree that a new study is required. The study may be a joint study, individual studies, or a single study provided by Entity A and reviewed and approved by Entity B. In this example, the latter will occur.
- Upon receipt of the above request for information, Entity B will provide the information within 30 calendar days, or an agreed upon time frame.
- Entity A will perform a PSCS using the information received.
- Entity A will provide a summary of the results of the study to Entity B within 90 calendar days of completing the PSCS.
- Entity B will review the summary information and, within 90 calendar days of receiving the study results from Entity A, respond as to whether any coordination issues were identified, and if any further action is required.
    - In cases where the study reveals that changes to Protection Systems are needed, Entity B would propose to Entity A revisions that achieve acceptable results.
    - Ultimately, both entities will collaborate in developing a mutually acceptable solution.

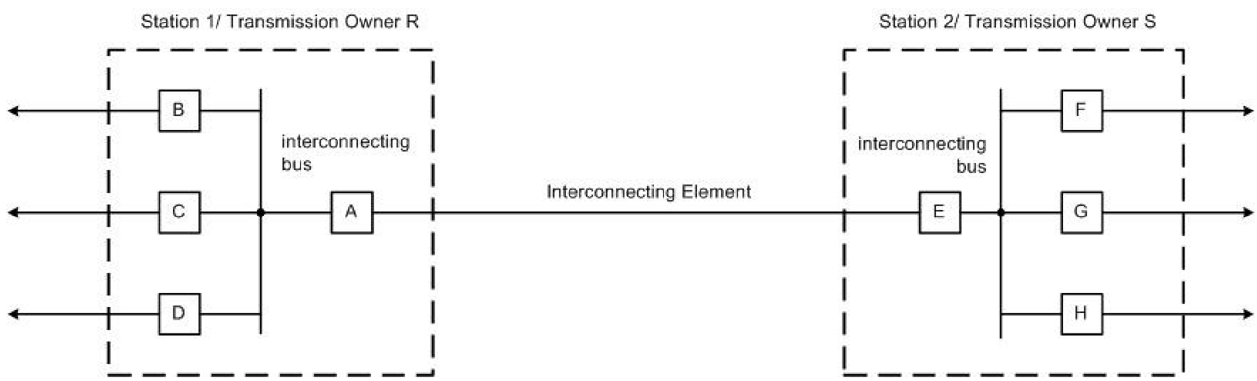
Diagrams

Introduction: The diagrams below are intended to provide guidance, to the owners of Facilities associated with the affected Interconnecting Element, for meeting the requirements of this standard. These examples are not intended to be inclusive of all situations and are based on the assumption that entities employ the appropriate engineering expertise and due diligence in developing settings for their Protection Systems. The examples given also assume a single owner as the initiator of a Protection System Coordination Study (PSCS) for the applicable Interconnecting Element. In actuality, any owner or owners may initiate the process. After the reviews of the PSCS or a summary of results, and prior to implementation of changes, the owners must work together to resolve any coordination issues identified during those reviews.

NOTES:

1. Protection System Coordination Studies are typically performed assuming maximum generation and all Facilities in service.
2. Protection Systems of the Transmission Owners, Generator Owners, and Distribution Providers described in the Figures and examples below do not include any systems or components enumerated in the 'Background Section' of this standard under "Other Aspects of Coordination of Protection Systems Addressed by Other Projects".
3. In the Figures below, the locations of the interconnecting bus(s) referenced in Requirement 2 are indicated.

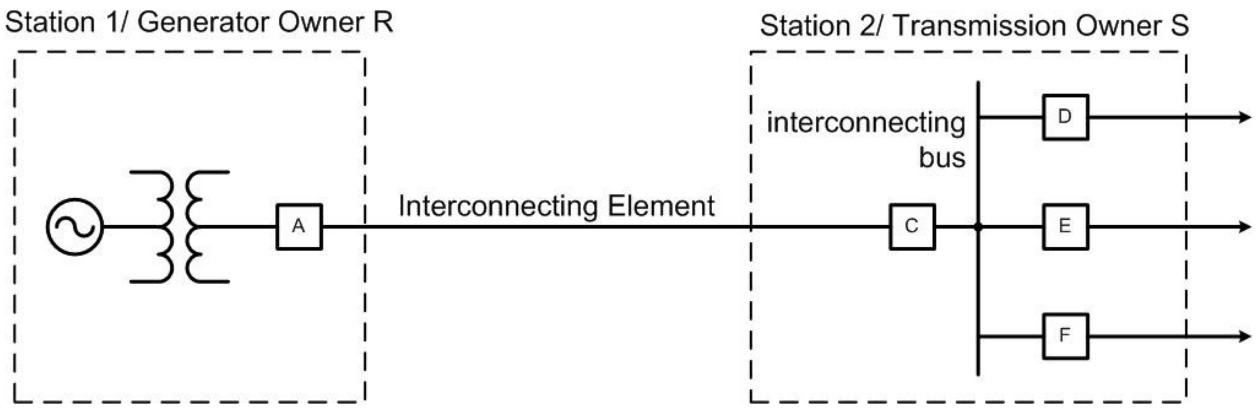
Figure 1



In Figure 1 above, the Interconnecting Element between the Transmission Owners is the transmission line between Breakers A and E.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 1, Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers E, F, G, and H. Likewise, Owner S is to develop Protection System settings associated with Breaker E. Owner R is to review the Protection System settings associated with Breaker E (provided by Owner S) for coordination issues with the Protection System settings associated with Breakers A, B, C, and D.

Figure 2

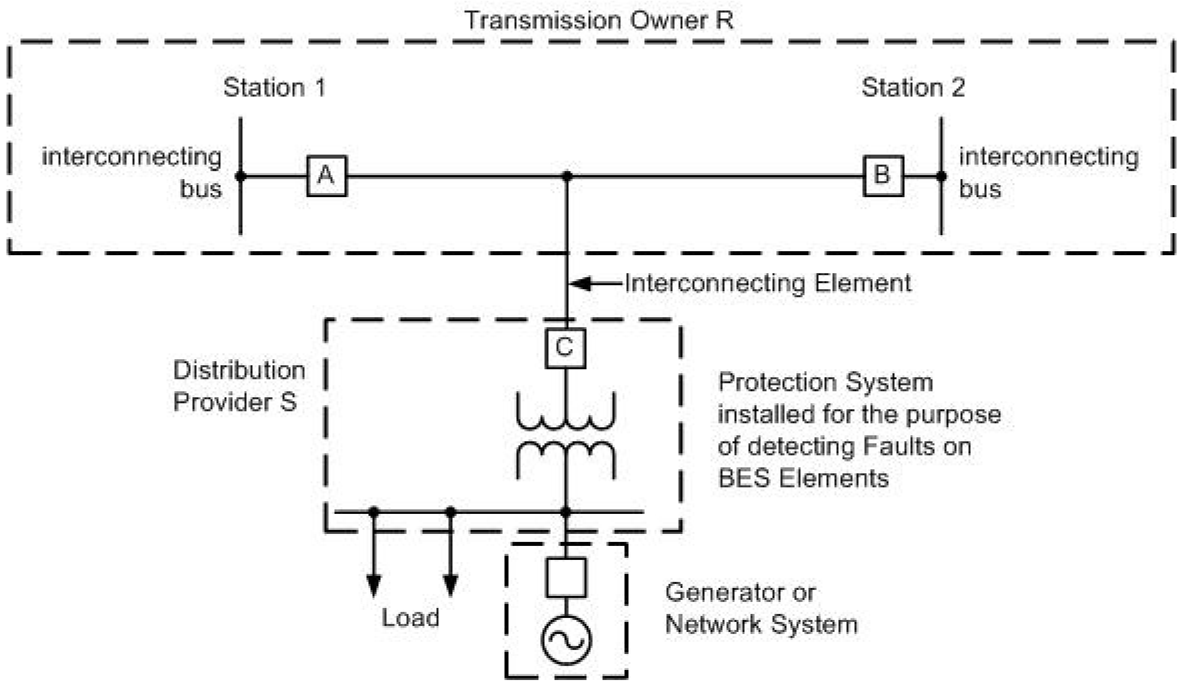


In Figure 2 above, the Interconnecting Element between the Transmission Owner and the Generator Owner is the transmission line or bus between Breakers A and C.

Note: Depending on the actual configuration and/or ownership, Breaker A may, or may not, exist as a GSU unit high-side breaker or a line breaker.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 2, Owner R is to develop Protection System settings associated with Breaker A. Transmission Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, Owner S is to develop Protection System settings associated with Breaker C. Generator Owner R is to review the Protection System settings associated with Breaker C (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

<u>Figure 3</u>



In Figure 3 above, the Interconnecting Element between the Transmission Owner and the Distribution Provider is the transmission line (or tap) between the Distribution Provider's Breaker C and the point of connection to the line between the Transmission Owner's Breakers A and B. Therefore, the applicable Protection Systems per this standard are those at Breakers A, B and C.

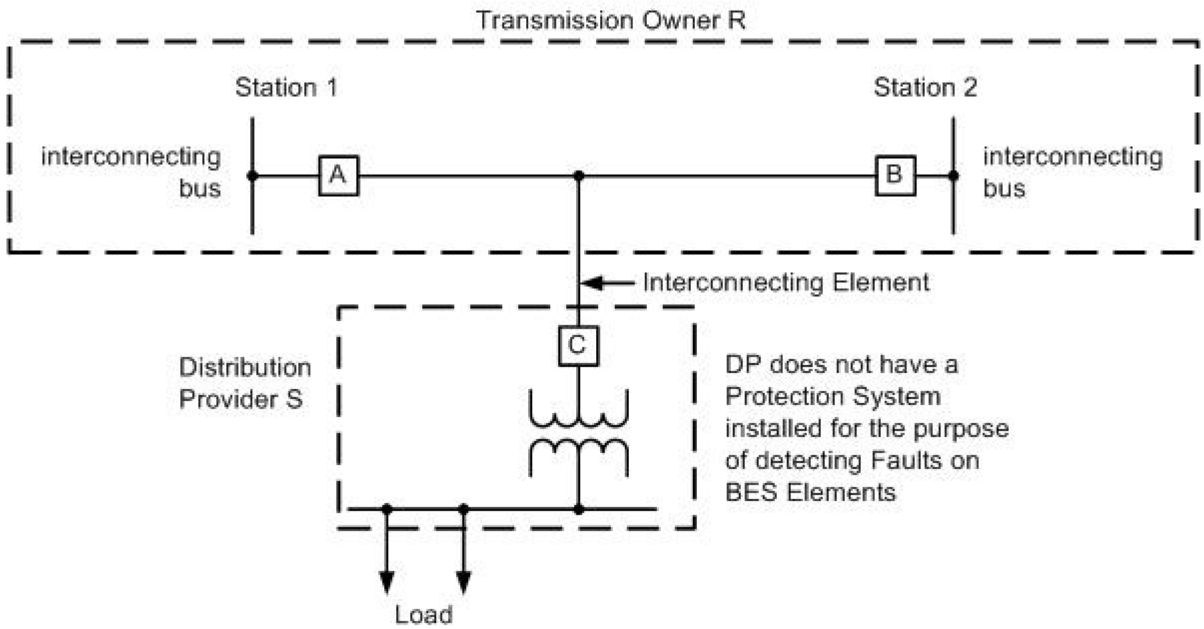
Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 3, Distribution Provider S is to develop Protection System settings associated with Breaker C. Transmission Owner R is to review the Protection System settings associated with Line Breaker C (provided by Distribution Provider S) for coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2.

Notes:

A PSCS is required per this standard for this example if a Protection System at the Distribution Provider's substation is installed for the purpose of detecting Faults on BES Elements.

Protection Systems installed for the purpose of detecting Faults on BES Elements do not include relays that, though they may operate for such Faults, are not installed specifically for that purpose. As an example, reverse power relays are often installed to detect situations where the transmission source for a power transformer becomes de-energized (for whatever reason) while the distribution bank remains energized from a source on the low-voltage side. In this case, the settings of the reverse power relay are typically calculated based on the charging current of the transformer from the low-voltage side. Although relays installed and set in this manner may operate as a result of a Fault on a BES Element, they are not specifically installed for the purpose of detecting that Fault.

Figure 4



The configuration above is an example excluded from this standard because the Distribution Provider S does not own Protection Systems installed for the purpose of detecting Faults on BES Elements.

Figure 5

Transmission/Generation Facility with Multiple Owners

Note: In a large majority of cases, Figure 2 would be applicable for most generator interconnections. In Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T.

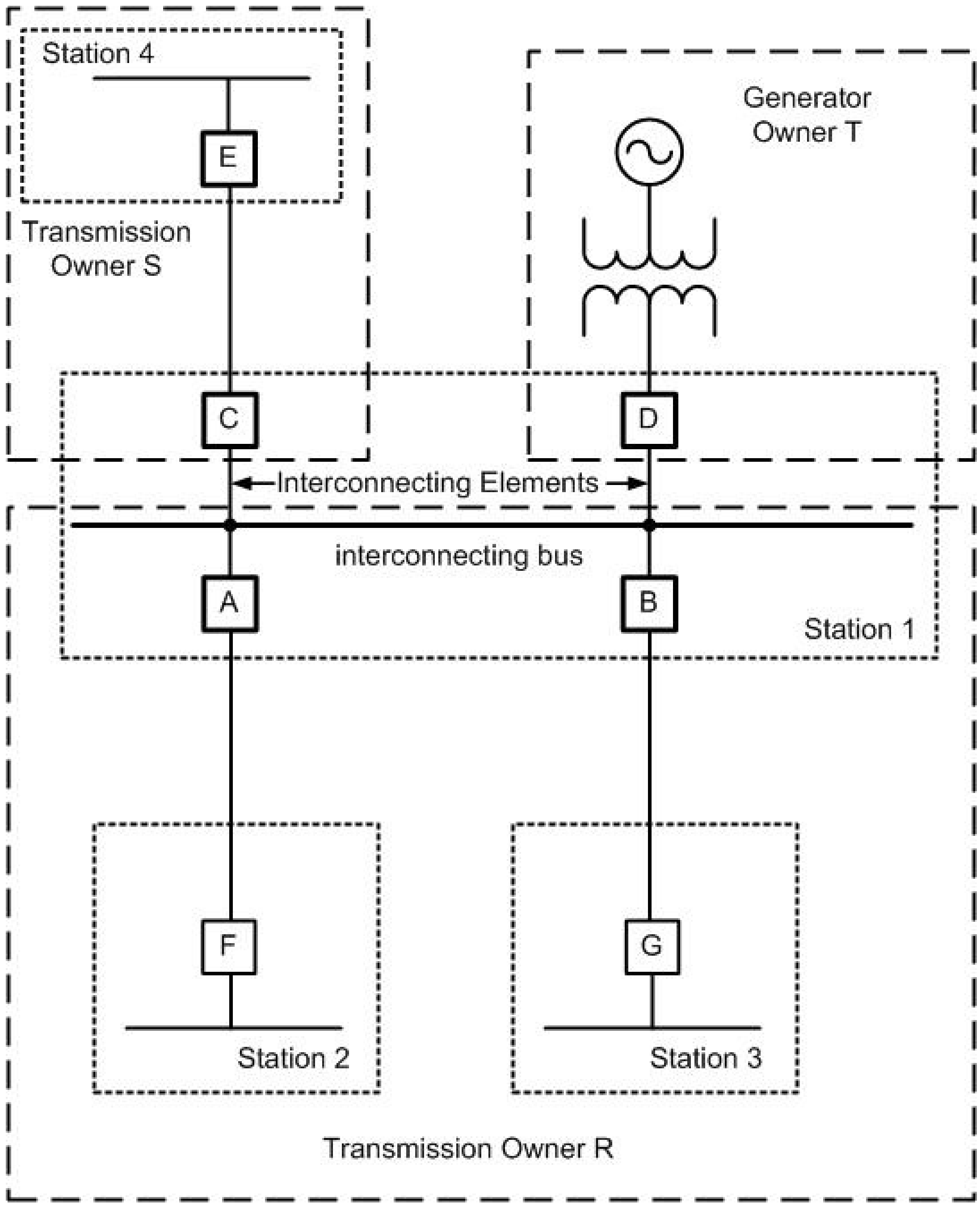


Figure 5 above illustrates the Interconnecting Elements between the Transmission Owners R and S and Generator Owner T. In this example, Transmission Owner S and Generator Owner T are not directly interconnecting to each other at Station 1. All direct interconnections are between Owner R and each of the other Owners connected to the common bus at Station 1.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 5:

Owner S is to develop Protection System settings associated with Breakers C and E.

Owner T is to develop Protection System settings associated with Breaker D, the generator, and its associated equipment.

Owner R is to develop Protection System settings associated with Breakers A, B, F and G.

Owner R is to review the Protection System settings associated with Breaker C, E, D, and the generator Protection System (provided by Owners S and/or T) for coordination issues with the Protection System settings associated with Breakers A and B.

Owner S is to review the Protection System settings associated with Breakers A, F, B, G, D, and the generator Protection System (provided by Owners R and/or T) for coordination issues with the Protection System settings associated with Breaker C. To perform this review, it will be necessary that Transmission Owner R provide Owner S with its settings for Breakers A, F, B, and G, as well as the settings for Breaker D and generator Protection System settings provided to Owner R by Generator Owner T.

Owner T is to review the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R and/or S) for coordination issues with the Protection System settings associated with Breaker D or the generator Protection System. In order to perform this review, it will be necessary that Transmission Owner R provide Generator Owner T with its settings for Breakers A, F, G, and B, as well as the settings for Breaker C and E provided to Owner R by Transmission Owner S.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Draft 1 of SAR posted for comment June 11, 2007 – July 10, 2007.
2. SAR approved on August 13, 2007.
3. First posting of revised standard PRC-001-2 on September 11, 2009.
4. Transitioned from a revision of PRC-001-1 to development of PRC-027-1 based on industry comments, Quality Review feedback, and consideration of FERC directives relative to the existing requirements of PRC-001-1.
5. Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012.
6. Draft 2 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from November 16 – December 17, 2012.
7. Draft 3 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from June 4 – July 3, 2013.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPC~~-~~SDT) created a new results-based standard, PRC-027-1,with the stated purpose 'to coordinate Protection Systems for ~~Interconnected~~Interconnecting Elements, such that Protection System components operate in the ~~desired~~intended sequence during Faults.' This standard incorporates and clarifies the coordination aspects of Requirements R2 and R3 from PRC-001-2 (formerly R3 and R4 of PRC-001-1). The SPC SDT is requesting a posting for stakeholder comments for a ~~30~~45-day formal comment period ~~with a parallel successive~~and ballot.

Anticipated Actions	Anticipated Date
~~30~~45-day Formal Comment Period with ~~Parallel Successive~~ Ballot	~~June~~September - November 2013
~~Conduct Recirculation~~Final Ballot	~~August~~December 2013
BOT Adoption	~~November 2013~~February 2014

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~shall become effective on the first day of the first calendar quarter that is 12 months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. For Interconnected Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.~~

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2007-06 – PRC-027-1	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here.

The following terms are defined for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

~~Interconnected~~Interconnecting Element: A BES Element that electrically joins ~~facilities~~ Facilities:
a) owned by~~:~~
~~a)~~ separate Registered Entities, or
b) owned by the same Registered Entity that represents multiple functional entity responsibilities (~~Distribution Provider~~Transmission Owner, Generator Owner, or ~~Transmission Owner~~Distribution Provider).

Protection System Coordination Study: A study that ~~demonstrates~~documents existing or proposed Protection Systems operate in the ~~desired~~intended sequence for clearing Faults.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. Title: **Protection System Coordination for Performance During Faults**

2. Number: PRC-027-1

3. Purpose: To coordinate Protection Systems for ~~Interconnected~~Interconnecting Elements, such that Protection System components operate in the ~~desired~~intended sequence during Faults.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider (that own Protection Systems identified in the Facilities section 4.2 below)

4.2 **Facilities:** ~~For the purpose of the requirements contained herein, the following~~

Protection Systems ~~owned by each Functional Entity in 4.1 above are those to which these requirements are applicable.~~:

a) ~~**4.2.1** Protection Systems~~ installed for the purpose of detecting Faults on ~~Interconnected~~Interconnecting Elements ~~of the BES~~, and

~~a)~~b) that require coordination for isolating those faulted Elements

5. Background:

On December 7, 2006, the NERC Planning Committee approved the assessment of Reliability Standard PRC-001 – System Protection Coordination, prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF noted problems with the applicability to entities and vagueness of requirements in the existing PRC-001-1 reliability standard. The SPCTF concluded that the deficiencies of Reliability Standard PRC-001-1 were magnified by having requirements that addressed coordination of protection functions and capabilities in the operating and planning timeframes. Consequently, the SPCTF recommended that the requirements for the operating horizon and planning horizon be clearly delineated, and possibly divided into two standards.

The NERC Standards Committee approved a Standard Authorization Request that included the modifications noted by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC-SDT) posted an initial draft of Reliability Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC-SDT attempted to address all issues identified by the SPCTF assessment of PRC-001-1. The SPC-SDT responded to the comments from the initial posting of PRC-001-2, and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC Quality Review (QR) in December 2010. Based on the results from the QR, and after informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to follow the SPCTF recommendation and focused their knowledge and expertise on developing a new results-based standard, concentrating on the reliability aspects (the coordination of new and existing protective systems in the planning horizon) associated with Requirements R3 and R4 of PRC-001-1. These aspects of coordination are incorporated and clarified in the proposed Reliability Standard PRC-027-1 – Protection System Coordination for Performance During Faults with the stated purpose:

> *"To coordinate Protection Systems for ~~Interconnected~~Interconnecting Elements, such that Protection System components operate in the ~~desired~~intended sequence during Faults."*

~~Additionally, the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21-C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address "the appropriate use of time delays in relays," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination.~~

PRC-001-1 contained a non-specific training requirement (Requirement R1), three operating time frame requirements (Requirements R2, R5 and R6), and two planning requirements (Requirements R3 and R4). The SPC~~-~~SDT transferred the responsibility of addressing the operating Requirements R2, R5, and R6 to the drafting team for Project 2007-03 Real-time Operations, charged with revising the TOP group of reliability standards. The Project 2007-03 drafting team retired Requirements R2, R5, and R6 of PRC-001-1 because they addressed data and data requirements that are now included in Reliability Standard TOP-003-2. The NERC Board of Trustees adopted Reliability Standards TOP-003-2 and PRC-001-2 on May 9, 2012.

~~The SPC SDT revised PRC-001-2. Revisions include the removal of Requirements R2 and R3 (formerly Requirements R3 and R4 of PRC-001-1). These two legacy requirements are being retired because the aspects of coordination they address are incorporated in the proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The SPCSDT believes the training aspects of Requirement R1 would be more appropriately addressed by the PER group of Reliability Standards. Consequently, the drafting team has recommended via the NERC Issues Database that the future drafting team charged with revising PER-005-1 incorporate the reliability objective of Requirement R1 into the revised standard. Until that occurs, Requirement R1 of PRC-001-2 must remain in the standard. In an effort to improve PRC-001-2 until it can be fully retired, the drafting team has provided a measure to accompany Requirement R1. The Applicability section was also updated to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)~~

The SPCSDT posted Draft 3 of PRC-027 in June, 2013 for comment and ballot. As part of that posting, the drafting team proposed revisions to PRC-001-2. The revisions were being proposed as an interim step to provide clarity to PRC-001 until it is retired. However, since this last posting, the informal initiative for revising PER-005-1 has transitioned to a formal project, Project 2010-01 Training. The proposed revisions to PER-005-1 address the reliability objective of PRC-001-2, Requirement 1. Proposed Reliability Standard PRC-027-1 incorporates the aspects of coordination in Requirements R2 and R3 of PRC-001-2.

Consequently, NERC staff and the SPCSDT are recommending the retirement of PRC-001-2. As such the drafting team is no longer considering changes to PRC-001-2. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for stakeholder review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.

Other Aspects of Coordination of Protection Systems Addressed by Other Projects:

Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects~~.~~:

- Underfrequency Load shedding programs are addressed in PRC-006-1. Generator performance during frequency excursions is being addressed in PRC-024-1 by Project 2007-09 Generator Verification.
- Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed in PRC-024-1 by Project 2007-09, Generator Verification.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is ~~being~~ addressed in PRC-019-1 by Project 2007-09, Generator Verification.
- Transmission relay loadability is addressed in PRC-023-2.
- Generator relay loadability is ~~will be~~ addressed in PRC-025-1 by Project 2010-13.2, Phase 2 of Relay Loadability: Generation~~, in Project 2010-13.2~~.
- Protective relay response during power swings will be addressed by ~~Phase 3 of~~ Project 2010-13.3, Phase 3 of Relay Loadability: Stable Power Swings.
- Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and ~~will be improved~~are addressed in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

The SPC SDT believes that including these other aspects of protection coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

B. Requirements and Measures

Rationale for R1:

Part 1.1 A Protection System Coordination Study (PSCS) is necessary to verify coordination of Protection Systems for existing and new ~~Interconnected~~Interconnecting Elements. The drafting team defines the term "~~Interconnected~~Interconnecting Element" as "A BES Element that electrically joins ~~facilities~~ Facilities: a) owned by~~: a)~~ separate Registered Entities, or b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner)."

Part 1.1.1 The drafting team believes 60 calendar months is an appropriate period of time for entities to perform the PSCS required where no study exists. The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with ~~Interconnected~~Interconnecting Elements that warrants a shorter time frame.

Part 1.1.2 The drafting team believes that 12 calendar months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater Fault current change at an interconnecting bus, where such conditions may warrant a new PSCS, or to technically justify why no such study is required~~, e.g., when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current~~. Refer to the Application Guidelines for Requirement R1 for examples of Protection Systems where technical justifications may be used.

Part 1.1.3 The drafting team believes that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, Part 3.1, or to technically justify why no such study is needed. The drafting team believes the timeframe associated with the requirement for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies ~~associated with Requirement R3, Part 3.1~~ is unnecessary because notification of such a change may occur weeks or years prior to the change. The initiating entity has the incentive to provide the identified information as soon as possible to ensure timely implementations.

Part 1.1.4 The drafting team believes that entities must perform the studies required when notified of changes identified in Requirement R3, Part 3.3, or to technically justify why no such study is needed. The drafting team believes that six months is an appropriate period of time for entities to perform the studies required or to technically justify why no such study is needed when details of changes are provided associated with Requirement R3 Part 3.3.

Part 1.2 The drafting team believes to properly ensure coordination of Protection Systems associated with ~~Interconnected~~Interconnecting Element(s), all entities need to share the summary of results of a PSCS and assess the study results. The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS performed in accordance with Requirement R1, Part 1.1 to the other owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element(s).

Note: In cases where a single group performs an overall coordination study for a given ~~Interconnected~~Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS ~~would be~~is sufficient for use by ~~both Registered Entities~~all entities.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

1.1. Perform a Protection System Coordination Study (PSCS) for each of its ~~Interconnected~~Interconnecting Elements as follows:

1.1.1 Within 60 calendar months after the effective date of this standard, if no PSCS for that ~~Interconnected~~Interconnecting Element exists.

1.1.2 Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required.

1.1.3 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or ~~within~~technically justify why such a study is not required.

~~1.1.3~~1.1.4 Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3~~;~~, or technically justify why such a study is not required.

1.2. Within 90 calendar days after the completion of each PSCS~~,~~ or the technical justification pursuant to Requirement R1, Part 1.1, provide to the other owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element(s~~),~~): a summary of the results of each PSCS performed~~ pursuant to Requirement R1, Part 1.1, (~~, including, at a minimum, the Protection Systems reviewed, the associated Fault ~~currents~~current(s) used, any issues identified, and any revisions or actions proposed~~).~~; or the technical justification.

M1. Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1,~~, and~~ 1.1.2, 1.1.3, and 1.1.~~3~~4 is a dated PSCS, or the summary of the results of each PSCS (hard copy or electronic file formats) demonstrating the time frames specified or agreed to in Parts 1.1.1, 1.1.2, 1.1.3, and 1.1.~~3~~4 were achieved. Acceptable evidence of a technical justification for not performing a PSCS as specified in Parts 1.1.2, 1.1.3, and 1.1.~~3~~4 -may include, but is not limited to, documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any ~~aspects~~aspect of coordination.

M2. Acceptable evidence for Requirement R1, Part 1.2 is dated documentation demonstrating that the summary of the results of each PSCS or the technical justification (hard copy or electronic file formats) were provided within the specified time frame to the owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element(s).

Rationale for R2: This requires a periodic review of Fault currents at the interconnecting bus and providing the results to the applicable entities when changes occur that meet the criteria of Requirement R2. It is important that ~~interconnected~~interconnecting Facility owners are kept aware of changes that could affect proper performance of their Protection Systems. The Transmission Owner is identified as the entity responsible for performing the short circuit studies because they maintain the data necessary to perform the studies. Note: short circuit studies are used to determine the Fault current values at the interconnecting bus where a PSCS exists. These studies are typically performed assuming maximum generation and all Facilities in service.

The drafting team believes 60 calendar months provides the entities flexibility to ~~either technically justify why Fault current does not affect the Protection System coordination, or~~ schedule and perform the activities specified in Requirement R2, Parts 2.1 and 2.2.

~~The drafting team recognizes the coordination of some types of Protection Systems is unaffected by changes in Fault current and, where technically justified, can be exempted from the short circuit review.~~

Part 2.1 The drafting team believes maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus are necessary quantities needed to review the coordination.

Part 2.2 The drafting team is including this equation to assure a consistent approach is used by each Transmission Owner when calculating the percent change in Fault current values.

Part 2.2.1 The drafting team believes the 30-calendar day time frame is reasonable for providing the Fault current information to the owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element. The drafting team determined that a change in Fault current of 10% indicates an appropriate point at which to provide this information, based on the fact that Protection Systems are typically set with margins above 10%.

R2. For each ~~Interconnected~~Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months~~, technically justify why Fault current does not affect the Protection System coordination, or~~: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

2.1. Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at ~~the~~its interconnecting bus(s) where a ~~Protection System Coordination Study (~~PSCS~~)~~ is available ~~per~~ pursuant to Requirement R1.

2.2. Calculate the percent change between the Fault current values (single line to ground and 3-phase for ~~the~~its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation:

$$\%\ Change = \left|\frac{Iscs - Ipscs}{Ipscs}\right| x\ 100$$

Where: I_{scs} = Fault current value from present short circuit study

And: I_{pscs} = Fault current value used in the most recent PSCS

2.2.1 Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (I_{scs}) to each owner of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element~~.~~(s).

~~**M3.** Acceptable evidence of technical justification for not performing a short circuit study as specified in Requirement R2, could be documented engineering analyses or assessments that demonstrate why Fault current does not impact any aspects of coordination.~~

~~M4.~~M3. Acceptable evidence for Requirement R2, Parts 2.1 and 2.2 is dated documentation (hard copy or electronic file formats) that contains the present Fault current values from the short circuit study for each interconnecting bus analyzed, and identifies the percent change from the Fault current values used in the most recent PSCS determined by the equation.

~~M5.~~M4. Acceptable evidence for Requirement R2, Part 2.2.1 is dated documentation (hard copy or electronic file formats) that the updated Fault current values (I_{scs}), were provided within the specified timeframe to each owner of the Protection System associated with the ~~Interconnected~~Interconnecting Element.

Rationale for R3: This requires the transfer of appropriate information to the entities associated with each ~~Interconnected~~Interconnecting Element due to circumstances identified in Parts 3.1, 3.2, and 3.3.

Part 3.1 The reliability objective of this requirement is to enable the process of conducting PSCSs by ensuring that the information is provided to the owner(s) of the Protection Systems associated with ~~Interconnected~~Interconnecting Element(s). The drafting team believes that information about any proposed change or addition (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the ~~Interconnected~~Interconnecting Element. The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list provided in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. Examples of changes to generator units that result in impedance changes could include replacements and re-ratings. This requirement also pertains to changes identified as a result of studies performed in Requirement 1, Part 1.1.

Part 3.2 The purpose of this requirement is to provide a means for an entity to receive the requested information in a timely manner in order to perform a PSCS, as required in Requirement 1, Parts 1.1.1, 1.1.2, 1.1.3, and 1.1.~~3~~4. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide this information. The requirement also provides some flexibility for the parties involved to determine an otherwise agreed-to schedule, if appropriate.

Part 3.3 The drafting team believes 30 calendar days is sufficient time to provide the information.

Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that describes the information listed in Requirement R3, Parts 3.1 and 3.3 below is sufficient for use by all entities.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same ~~Interconnected~~Interconnecting Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the ~~Interconnected~~Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the ~~Interconnected~~Interconnecting Element(s).

- New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios
- Changes to a transmission system Element that alter any sequence or mutual coupling impedance
- Changes to generator unit(s) that result in a change in impedance

- Changes to the generator step-up transformer(s) that result in a change in impedance

3.2. Requested information related to the coordination of Protection Systems associated with an ~~Interconnected~~Interconnecting Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule.

3.3. Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.

~~M6.~~M5. Acceptable evidence for Requirement R3, Part 3.1 may include, but is not limited to, documentation (hard copy or electronic file formats) demonstrating that a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) as identified in the bulleted list, was provided to each responsible entity connected to the same ~~Interconnected~~Interconnecting Element.

~~M7.~~M6. Acceptable evidence for Requirement R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was provided according to the agreed-upon schedule, or within 30 calendar days absent such an agreement.

~~M8.~~M7. Acceptable evidence for Requirement R3, Part 3.3 is dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the permanent changes made was provided within 30 calendar days.

Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with ~~Interconnected~~ Interconnecting Elements ~~affirm~~confirm that the Protection System(s) applied ~~are acceptable per~~were reviewed and a response was provided to the ~~conditions identified in Parts 4.1 and 4.2~~other owner(s). The review assures that the owners of Protection Systems associated with the affected Interconnecting Element are aware of the changes and have responded with comments if necessary.

~~Part 4.1~~ The drafting team believes 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with ~~Interconnected~~Interconnecting Elements to review the summary results of a PSCS or the technical justification and respond. Note: ~~Per~~Pursuant to Requirement R1, Part 1.2, at a minimum, the summary of the results of a PSCS must include the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. The response should indicate ~~acceptance with~~ the ~~review~~ results~~/conclusions; or rejection~~ of ~~or disagreement with~~ the ~~review results/conclusions~~PSCS or the technical justification were reviewed and ~~offer of suggestions/modifications to resolve~~, if applicable, any identified ~~coordination~~ issues.

Note: The drafting team recognizes there could be situations where one owner may not agree with the other owner's protection philosophy but they ~~accept the proposed changes since~~ can confirm that there were no identified coordination issues ~~were identified~~.

~~Part 4.2 The drafting team believes that proposed changes or modifications (including project schedules) to Facilities associated with the Interconnected Element, as described in Requirement R3, Part 3.1, or modifications suggested in Requirement R4, Part 4.1 must be communicated and accepted prior to the in-service date. Acceptance assures that the coordination of Protection Systems associated with the affected Interconnected Element is achieved.~~Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that describes the information listed in Requirement R3, Parts 3.1 and 3.3 below is sufficient for use by all entities.

~~R4.~~ Each Transmission Owner, Generator Owner, and Distribution Provider that received a summary of the results of a PSCS or a technical justification explaining why a PSCS is not required (pursuant to Requirement R1, Part 1.2) shall~~: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]~~

~~R5.~~R4. ~~Within~~, within 90 calendar days after receipt~~,~~ or according to an agreed upon schedule, review the summary of the results ~~of a PSCS (per Requirement R1, Part 1.2)~~or the technical justification, and respond to the other owner(s~~):~~) either: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- ~~Accepting~~Confirming that the ~~results, or~~
- ~~Rejecting~~summary of the results was reviewed and ~~suggesting modifications to resolve any identified~~no ~~coordinati~~coordination issues were identified, ~~on issues.~~
- ~~Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1~~ or ~~Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.~~
- Confirming that the summary of the results was reviewed and any identified coordination issue(s) were noted, or
- Confirming that a technical justification was reviewed and no issue(s) were identified, or
- Confirming that a technical justification was reviewed and any identified issue(s) were noted

~~M9.~~M8. Acceptable evidence for Requirement R4~~, Part 4.1~~ is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement.

Rationale for R5: This requirement ensures owner(s) of Protection System(s) associated with Interconnecting Elements have communicated and addressed any identified coordination issues prior to implementing changes in the Protection System(s) (i.e., the in-service date of the Protection System(s)).

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that received a response pursuant to Requirement R4 shall address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

~~M10.~~M9. Acceptable evidence for Requirement ~~R4, Part 4.2~~R5 is dated documentation (hardcopy or electronic file formats) demonstrating that~~,~~ a response pursuant to Requirement R4 was received and that any identified coordination issues were addressed prior to implementation of any proposed Protection System(s) changes or ~~modifications, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted~~additions.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System associated with an ~~Interconnected~~Interconnecting Element shall each keep data or evidence to show compliance with Requirements R1, R2, R3, R4, and ~~R4~~R5, and Measures M1 through ~~M10~~M9, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner or Distribution Provider that owns a Protection System at a Facility associated with an ~~Interconnected~~Interconnecting Element is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. ~~OR~~ OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required but was late by more than 60 calendar days. ~~OR~~ ~~The responsible entity provided the Protection System~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			with Requirement R1, Part 1.2, but was late by less than or equal to 10 calendar days.	10 calendar days but less than or equal to 20 calendar days.	20 calendar days but less than or equal to 30 calendar days.	~~Coordination Study~~ OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar days. OR The responsible entity failed to perform a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element in accordance with Requirement R1, Parts 1.1.1, 1.1.2, 1.1.3, or 1.1.~~3~~4. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2, 1.1.3, or 1.1.~~3~~4. OR The responsible entity failed to provide a summary of the results of each Protection System Coordination Study

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~results~~ or a technical justification in accordance with Requirement R1, Part 1.2.
R2	Operations Planning, Long-term Planning	Medium	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by less than or equal to 30 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study, as required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days.	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 30 calendar days but less than or equal to 60 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 60 calendar days but less than or equal to 90 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 90 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 90 calendar days. OR The Transmission Owner failed to perform a short circuit study, as required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent change between the Fault

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	currents, according to the equation designated in Requirement R2, Part 2.2. OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the updated Fault current values, as required in Requirement R2, Part 2.2.1.
R3	Operations Planning, Long-term Planning	Medium				The responsible entity failed to provide the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, details for any proposed change or addition identified in Requirement R3, Part 3.1. OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the information required in Requirement R3, Part 3.3.
R4	Operations Planning, Long-term Planning~~Operations Planning~~	Medium	The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following ~~the~~ receipt of the Protection System Coordination Study summary of the results ~~of the Protection System Coordination Study~~or technical justification, as required in Requirement R4~~, Part 4.1.~~	The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1.~~	The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1.~~	The responsible entity responded in more than 120 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1~~. OR The responsible entity failed

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			.	.	.	to review the ~~summary results of the~~ Protection System Coordination Study summary of the results -or the technical justification provided to them in accordance with Requirement R4~~, Part 4.1~~. OR The responsible entity failed to respond to the other owners(s) in accordance with Requirement R4~~, Part 4.1.~~ ~~OR~~ ~~The responsible entity failed to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element accepted the Protection System(s) changes including the resolution of any identified coordination issues, prior to implementation of those changes, as required in Requirement R4, Part 4.2~~.
R5	Operations Planning, Long-term Planning	Medium				The responsible entity failed to address any identified coordination issue(s), prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) in

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						accordance with Requirement R5.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Purpose:

To coordinate Protection Systems for ~~Interconnected~~Interconnecting Elements, such that Protection System components operate in the ~~desired~~intended sequence during Faults.

This standard requires that separate Registered Entities communicate with each other to coordinate Protection System components on existing ~~Interconnected~~Interconnecting Elements; and communicate with each other prior to the energization of new or modified Protection Systems associated with ~~Interconnected~~Interconnecting Elements. The goal of the coordination is to verify that the Protection Systems intended for sensing Faults will operate in the ~~desired~~intended sequence for internal and external Faults on the ~~Interconnected~~Interconnecting Element.

Requirement R1:

This requirement directs the applicable entities to perform a Protection System Coordination Study (PSCS) for every ~~Interconnected~~Interconnecting Element to verify coordination of existing Protection Systems where no recent study exists; or when Facility configuration changes are made, or where Fault current changes of 10% or more have occurred. In developing the language to define a PSCS, the System Protection Coordination Standard Drafting Team (SPC SDT) considered various reference books discussing protective relaying theory and application, along with the following description of "coordination of protection" from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Using the reference material cited above as guidance, the drafting team defined the term Protection System Coordination Study (PSCS) for use within the PRC-027-1 Reliability Standard as:

> "A study that ~~demonstrates~~documents existing or proposed Protection Systems operate in the ~~desired~~intended sequence for clearing Faults."

PSCSs comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in PSCSs include maximum generation with the transmission system under normal operating conditions and under single contingency conditions. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and

sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), and adequate directional polarizing quantities.

Part 1.1.1:

The drafting team believes applicable entities should have a documented PSCS for each ~~Interconnected~~Interconnecting Element to validate the Protection Systems associated with those ~~Interconnected~~Interconnecting Elements perform in a manner consistent with the purpose of this Standard. Additionally, the drafting team believes that 60 calendar months is an appropriate amount of time for entities to perform the initial studies expected under this requirement. This period considers the time some entities may require to create project scopes, acquire proposals, and secure contracts to hire external resources that may be needed to perform the studies. The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with ~~Interconnected~~Interconnecting Elements that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.

~~Parts 1.1.2 and 1.1.3 further direct that PSCSs must be completed under the following two circumstances:~~

Part 1.1.2:

After notification of an identified 10% or greater change in Fault current (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1), the notified entities must perform a new PSCS of the ~~Interconnected~~Interconnecting Element or document why a study is not required. The drafting team recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater change in Fault current may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the 12-calendar month time frame associated with this requirement represents a reasonable period to perform the studies that are required after identification by the 60-calendar month Fault current review.

Part 1.1.3:

After proposing or being notified of a change at a Facility associated with the ~~Interconnected~~Interconnecting Element, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the proposed or notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes the timeframe associated with performing a PSCS for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3, Part 3.1 is unnecessary because notification of such a change may occur weeks or years prior to the change due to the wide variety of conditions that may be associated with a particular change. The drafting team sees the entity initiating any change as having the incentive to move this along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement ~~R4,~~ R5.

Part 1.1.4~~.2.~~:

After being notified of a change at a Facility associated with the Interconnecting Element associated with Requirement R3, Part 3.3, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team believes that six calendar months is an appropriate period of time for entities to perform the studies required, or to technically justify why no such study is needed~~, when details of changes are provided associated with Requirement R3 Part 3.3~~.

Examples of Protection Systems where technical justifications may be used include:

1. Differential elements
2. Distance elements where infeed is not used in determining reach for the protection scheme.
3. Supervised overcurrent elements enabled by:
   - Loss of potential condition
   - Some communication assisted tripping
   - Switch-Onto-Fault (SOTF)
4. Reverse power, definite time &/or time overcurrent elements:
   - Designed to coordinate during maximum generation with the transmission system under normal operating conditions and under single contingency conditions regardless of Fault current.
   - Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.).

Requirement R1, Part 1.2 directs the entity performing the PSCS to provide a summary of the study results or a technical justification to the affected ~~Interconnected~~Interconnecting Element owner(s).~~-~~ The drafting team believes that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS it performed to the other owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element(s). (Note: In cases where a single group performs an overall coordination study for a given ~~Interconnected~~Interconnecting Element; a single document that meets the requirements for a summary of the results of the PSCS would be sufficient for use by both Registered Entities.) ~~As guidance, the drafting team lists the~~The following inputs and results of a PSCS ~~that may~~must be included in the summary provided pursuant to this requirement:

1. A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Facility, and which were reviewed for coordination of protective relays as part of the study, including the contingencies used in the evaluation.
2. A listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Facility under study.
3. A listing of any issues associated with the relay settings of the other owner(s) at the Facility that were identified by the study.
4. Any proposed revisions to a Protection System or its protective relay settings that were identified by the study.

Requirement R2:

The drafting team investigated various inputs that would trigger a review of the existing PSCSs and determined, through the experience of the drafting team members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated PSCS may be necessary. These variations could result from the accumulation of incremental changes over time. This requirement mandates the Transmission Owner ~~either provide a technical justification stating why Fault current does not affect the Protection System coordination of a specific Interconnected Element or~~ perform a periodic review of Fault currents.

~~**Examples of Protection Systems where technical justifications may be used include:**~~

~~5. Differential elements~~

~~6. Distance elements where infeed is not used in determining reach for the protection scheme.~~

~~7. Supervised overcurrent elements enabled by:~~

- ~~Loss of potential condition~~
- ~~Some communication assisted tripping~~
- ~~Switch-Onto-Fault (SOTF)~~

~~8. Reverse power, definite time &/or time overcurrent elements:~~

- ~~Designed to coordinate during maximum generation with the transmission system under normal operating conditions and under single contingency conditions regardless of Fault current.~~

- ~~Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.).~~

The short circuit study provides the Fault current values used to calculate the percent change between the most recent PSCS and the present Fault current values indicated by the short circuit study performed pursuant to Requirement R2, Part 2.1. This calculation is necessary to identify Fault current changes that must be communicated in accordance with Requirement R2, Part 2.2. Short circuit studies are typically performed assuming maximum generation and all Facilities in service.

The drafting team believes that 60 calendar months is an appropriate interval for ~~technically justifying why Fault currents do not affect the Protection System coordination of a specific Interconnected Element, or for~~ reviewing Fault currents. The drafting team believes studies associated with changes that would affect the coordination in less than 60 calendar months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.2.1 further directs the Transmission Owner to, within 30 calendar days, inform each owner of the Facility associated with the ~~Interconnected~~Interconnecting Element when short circuit studies indicate that 10% changes in Fault current have occurred at the interconnecting bus(s). The drafting team believes the 30-calendar day time frame associated with this requirement is reasonable for providing the Fault current information to the ~~interconnected~~interconnecting entity(s) and is consistent with other NERC reliability standards.

In Requirement R2, the Transmission Owner is identified as the functional entity responsible for performing the short circuit studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.

Requirement R3:

This directs the registered functional entity initiating any proposed change or addition to provide the details to the other affected entities of the ~~Interconnected~~Interconnecting Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes. Documentation provided to these other owners may include, but is not limited to, power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings. The recipient will incorporate the applicable information into its PSCSs to evaluate whether changes are required.

The list of applicable changes provided in Requirement R3, Part 3.1 is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. The drafting team recognizes that Facility changes at other locations can impact the PSCS of the Facility associated with the ~~Interconnected~~Interconnecting Element; e.g., the addition of a large autotransformer bank or generator not directly connected to the ~~Interconnected~~Interconnecting Element. The drafting team believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the drafting team sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule~~ and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2~~.

Requirement R3, Part 3.2 allows for entities to agree upon a schedule, appropriate to the circumstances, for providing the details needed to conduct a PSCS or, absent such agreement, within 30 calendar days of a request for this information. This requirement provides a means for entities to receive requested information in a timely manner. In consideration of circumstances where the information may not be readily available or may be incomplete due the retirement of personnel, the purging of records, change of ownership, etc., it also provides the flexibility of mutually agreeing to a schedule for exchanging information. The drafting team believes 30 calendar days after receipt of the request is a sufficient amount of time to provide the requested information where no other agreement exists.

~~Additionally, this requirement~~Requirement R3, Part 3.3 includes a provision for providing details associated with changes to the previously agreed-upon coordination when permanent changes are made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components. Based upon the limited number of instances that would occur under such circumstances, the drafting team believes 30 calendar days after determining that changes are required is an appropriate time frame for providing the associated details to affected entities.

Requirement R4:

Requirement R4directs applicable entities, within 90 calendar days after receipt, to review the summary results of a PSCS or the technical justification, as described in Requirement R1, Part 1.2; and respond that they have reviewed and identified any issues. The drafting team believes 90 calendar days after receipt provides a reasonable time for the owners of Facilities to review.

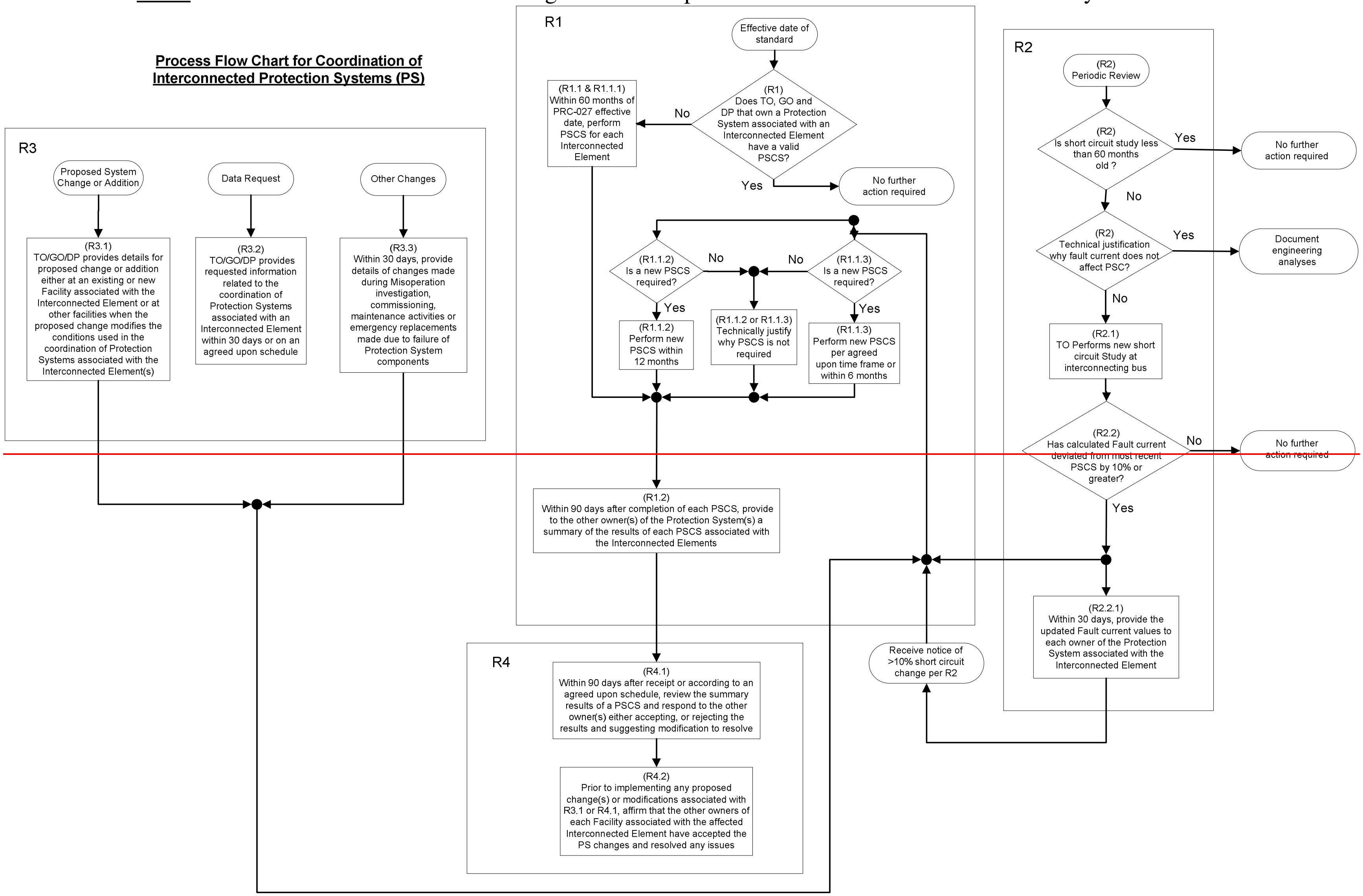
Requirement R5:

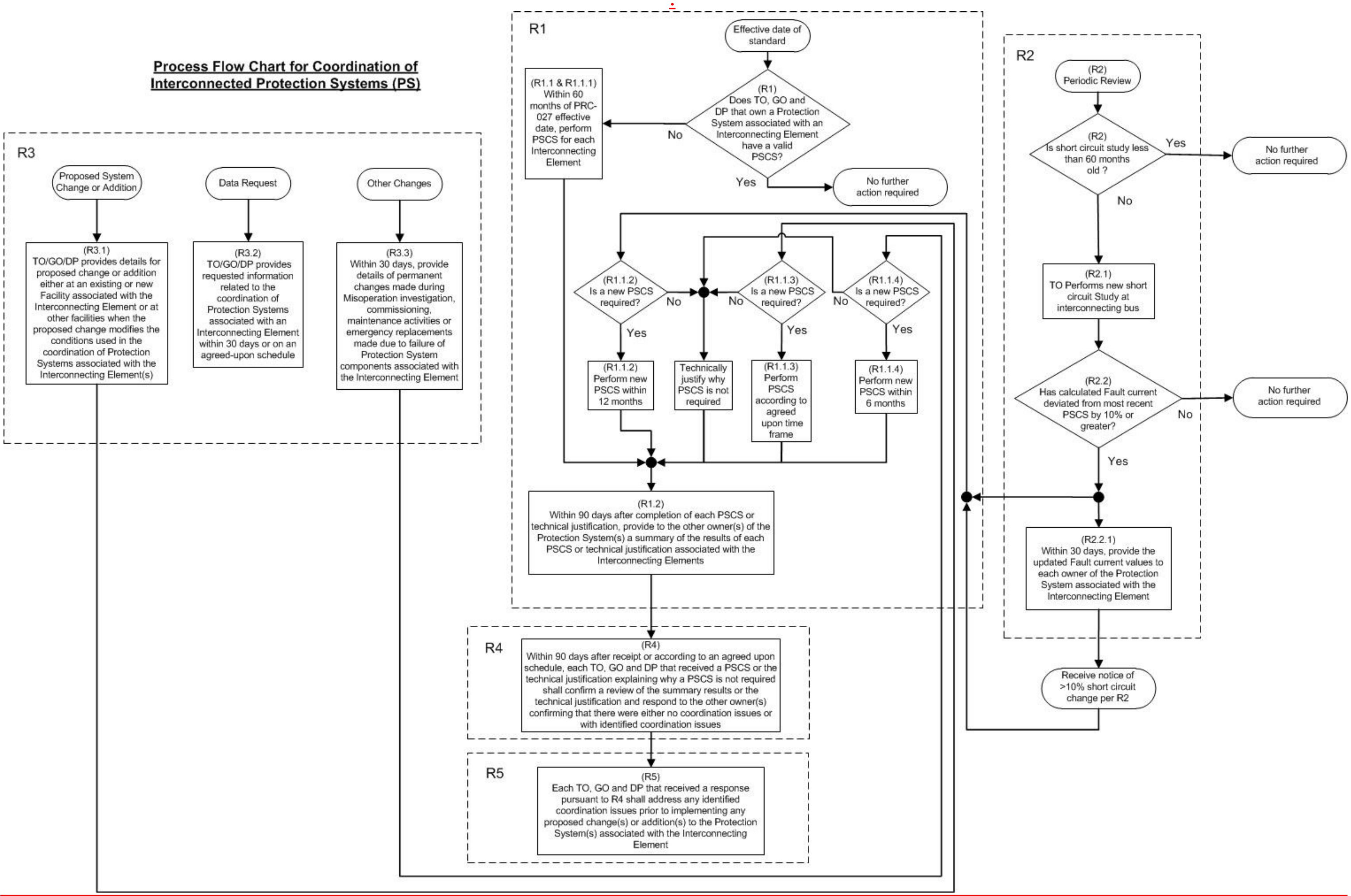
The reliability objective of this requirement is to bring the process of Protection System coordination full circle by ~~gaining the confirmation of interconnected entities that their Protection Systems are coordinated consistent with the purpose of this standard. Cooperative participation of Facility owners in communicating Protection System(s) design, and study results will achieve coordination of Protection Systems for reliable operation of the BES during Faults.~~ensuring owners of Protection System(s) associated with Interconnecting Elements have communicated and addressed any identified coordination issues prior to implementing changes in the Protection System(s) (in-service date).

~~Requirement R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to review the summary results of a PSCS, as described in Requirement R1, Part 1.2; and respond as to whether they accepting or rejecting the results, and if rejecting, suggesting modifications to resolve any identified coordination issues. The drafting team believes 90 calendar days after receipt of the results of a PSCS provides a reasonable time for the owners of Facilities to review the summary results of a PSCS.~~

~~Requirement R4, Part 4.2 directs entities to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes as described in Requirement 3, Part 3.1 and Requirement 4, Part 4.1 prior to the in-service date of those changes. Any coordination issues identified during the review must be resolved prior to implementing the proposed changes. The purpose of Requirement 4, Part 4.2 is to assure the effects the proposed changes have on Protection Systems at a Facility associated with the Interconnected Element have been considered by all affected entities.~~

Process Flow Chart: Below is a complete representation of the process, including the relationships between requirements:
Note: All timeframes referenced in the diagram below represent "calendar month" or "calendar day" timeframes~~.~~




Process Flow Chart for Coordination of Interconnected Protection Systems (PS)
R1
Effective date of standard
(R1) Does TO, GO and DP that own a Protection System associated with an Interconnecting Element have a valid PSCS?
No
Yes
(R1.1 & R1.1.1) Within 60 months of PRC-027 effective date, perform PSCS for each Interconnecting Element
No further action required
(R1.1.2) Is a new PSCS required?
(R1.1.3) Is a new PSCS required?
(R1.1.4) Is a new PSCS required?
No
Yes
(R1.1.2) Perform new PSCS within 12 months
Technically justify why PSCS is not required
(R1.1.3) Perform PSCS according to agreed upon time frame
(R1.1.4) Perform new PSCS within 6 months
(R1.2) Within 90 days after completion of each PSCS or technical justification, provide to the other owner(s) of the Protection System(s) a summary of the results of each PSCS or technical justification associated with the Interconnecting Elements
R2
(R2) Periodic Review
(R2) Is short circuit study less than 60 months old ?
Yes
No
No further action required
(R2.1) TO Performs new short circuit Study at interconnecting bus
(R2.2) Has calculated Fault current deviated from most recent PSCS by 10% or greater?
No further action required
(R2.2.1) Within 30 days, provide the updated Fault current values to each owner of the Protection System associated with the Interconnecting Element
Receive notice of >10% short circuit change per R2
R3
Proposed System Change or Addition
Data Request
Other Changes
(R3.1) TO/GO/DP provides details for proposed change or addition either at an existing or new Facility associated with the Interconnecting Element or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s)
(R3.2) TO/GO/DP provides requested information related to the coordination of Protection Systems associated with an Interconnecting Element within 30 days or on an agreed-upon schedule
(R3.3) Within 30 days, provide details of permanent changes made during Misoperation investigation, commissioning, maintenance activities or emergency replacements made due to failure of Protection System components associated with the Interconnecting Element
R4
(R4) Within 90 days after receipt or according to an agreed upon schedule, each TO, GO and DP that received a PSCS or the technical justification explaining why a PSCS is not required shall confirm a review of the summary results or the technical justification and respond to the other owner(s) confirming that there were either no coordination issues or with identified coordination issues
R5
(R5) Each TO, GO and DP that received a response pursuant to R4 shall address any identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element

Example Process

An example of the interaction between entities required to gather the information to perform an accurate study is provided below. This example is given as general guidance only and is not intended to represent all situations that may occur. More detailed examples are provided along with Figures 1-5 in the section that follows this example.

- The initiating entity (Entity A) will contact the ~~interconnected~~interconnecting entity (Entity B) and provide details of the ~~proposed~~ change(s) and may also request up-to-date Protection System information.
- Entities A and B will determine whether a new PSCS is required. In this example both agree that a new study is required. The study may be a joint study, individual studies, or a single study provided by Entity A and reviewed and approved by Entity B. In this example, the latter will occur.
- Upon receipt of the above request for information, Entity B will provide the information within 30 calendar days, or an agreed upon time frame.
- Entity A will perform a PSCS using the information received.
- Entity A will provide a summary of the results of the study to Entity B within 90 calendar days of completing the PSCS.
- Entity B will review the summary information and, within 90 calendar days of receiving the study results from Entity A, respond as to whether any coordination issues were identified, and if any further action is required.
    - In cases where the study reveals that changes to Protection Systems are needed, Entity B would propose to Entity A revisions that achieve acceptable results.
    - Ultimately, both entities will collaborate in developing a mutually acceptable solution.

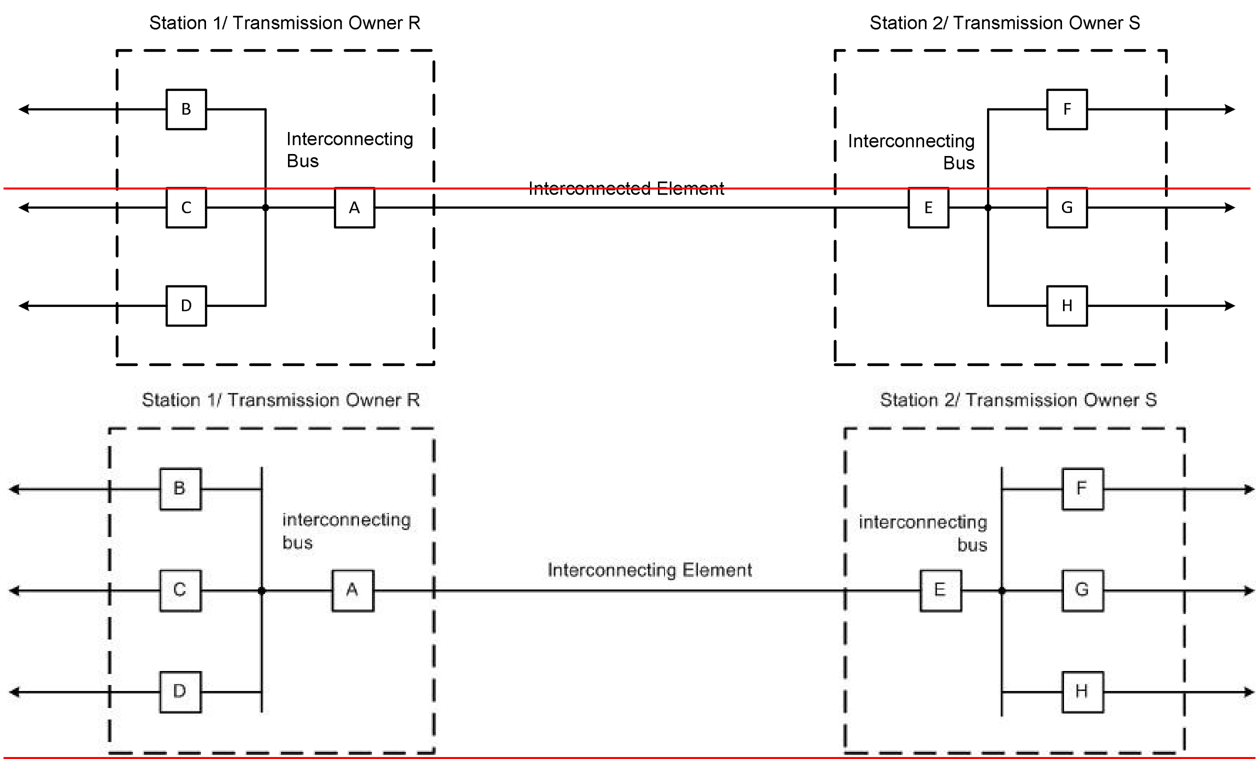
Diagrams

Introduction: The diagrams below are intended to provide guidance, to the owners of Facilities associated with the affected ~~Interconnected~~Interconnecting Element, for meeting the requirements of this standard. These examples are not intended to be inclusive of all situations and are based on the assumption that entities employ the appropriate engineering expertise and due diligence in developing settings for their Protection Systems. The examples given also assume a single owner as the initiator of a Protection System Coordination Study (PSCS) for the applicable ~~Interconnected~~Interconnecting Element. In actuality, any owner or owners may initiate the process. After the reviews of the PSCS or a summary of results, and prior to implementation of changes, the owners must work together to resolve any coordination issues identified during those reviews.

NOTES:

1. Protection System Coordination Studies are typically performed assuming maximum generation and all Facilities in service.
2. Protection Systems of the Transmission Owners, Generator Owners, and Distribution Providers described in the Figures and examples below do not include any systems or components enumerated in the 'Background Section' of this standard under "Other Aspects of Coordination of Protection Systems Addressed by Other Projects".
3. In the Figures below, the locations of the interconnecting bus(s) referenced in Requirement 2 are indicated.

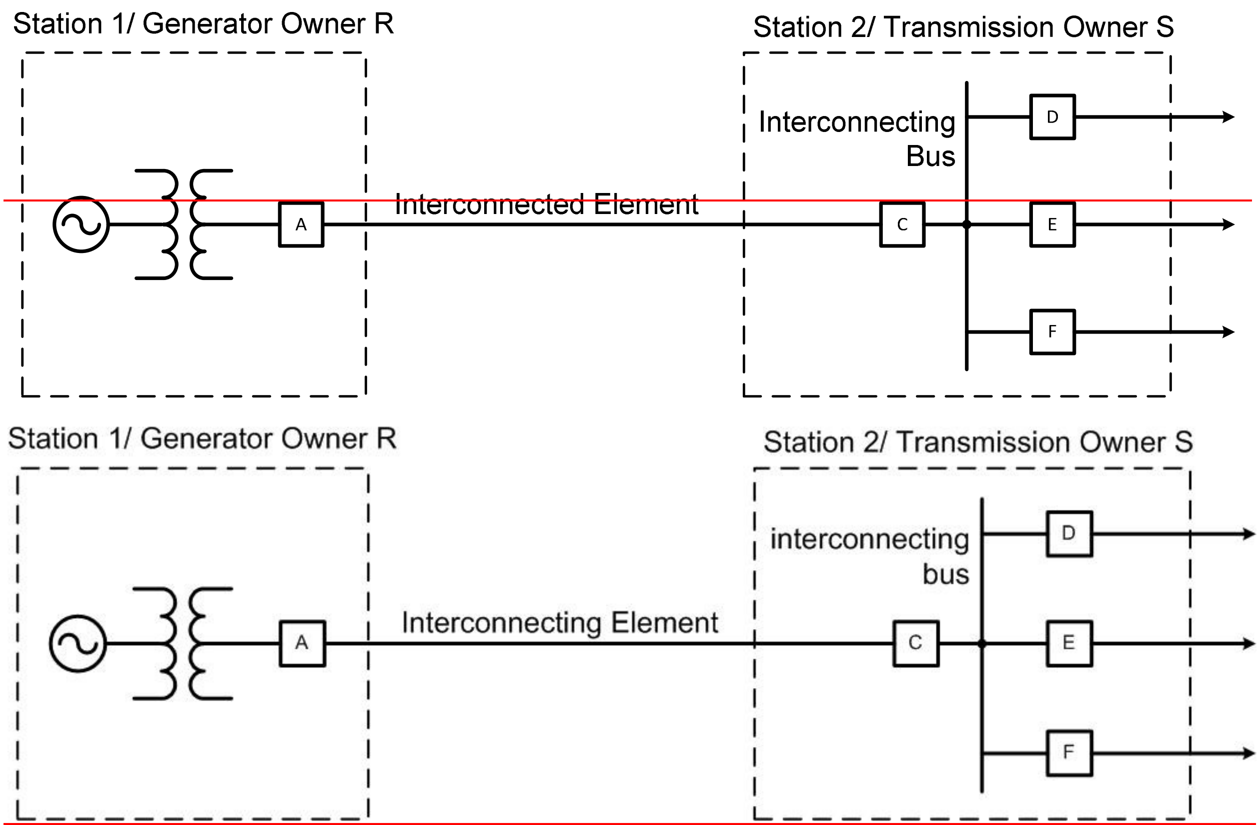
Figure 1



In Figure 1 above, the ~~Interconnected~~Interconnecting Element between the Transmission Owners is the transmission line between Breakers A and E.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 1, Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers E, F, G, and H. Likewise, Owner S is to develop ~~proposed~~ Protection System settings associated with Breaker E. Owner R is to review the Protection System settings associated with Breaker E (provided by Owner S) for coordination issues with the Protection System settings associated with Breakers A, B, C, and D.

Figure 2

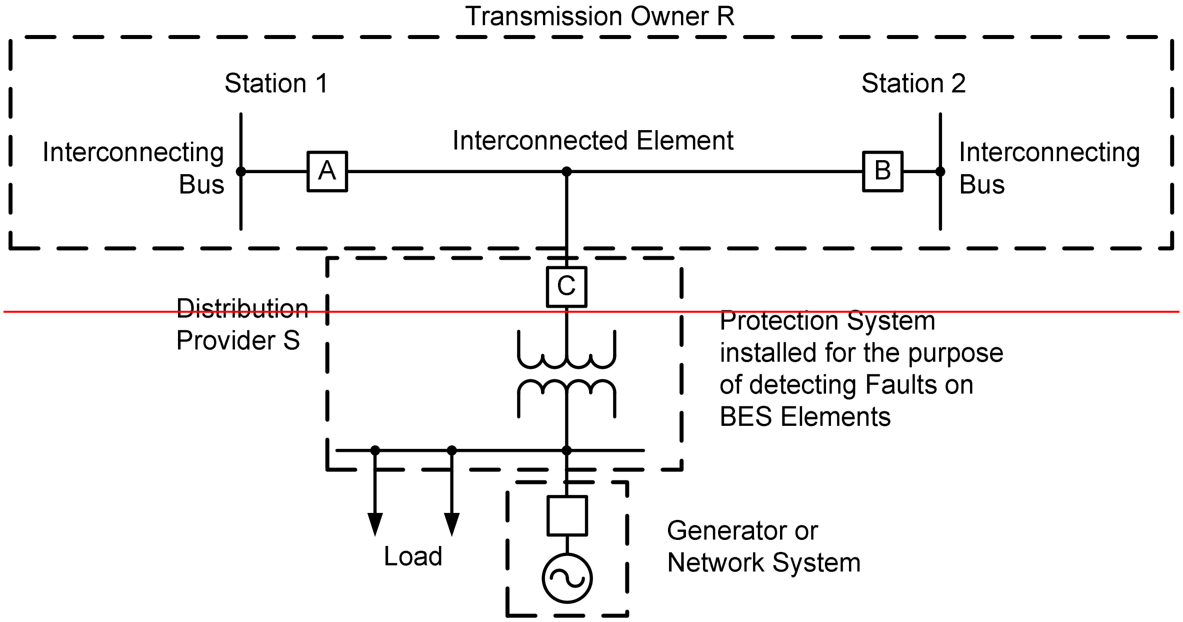


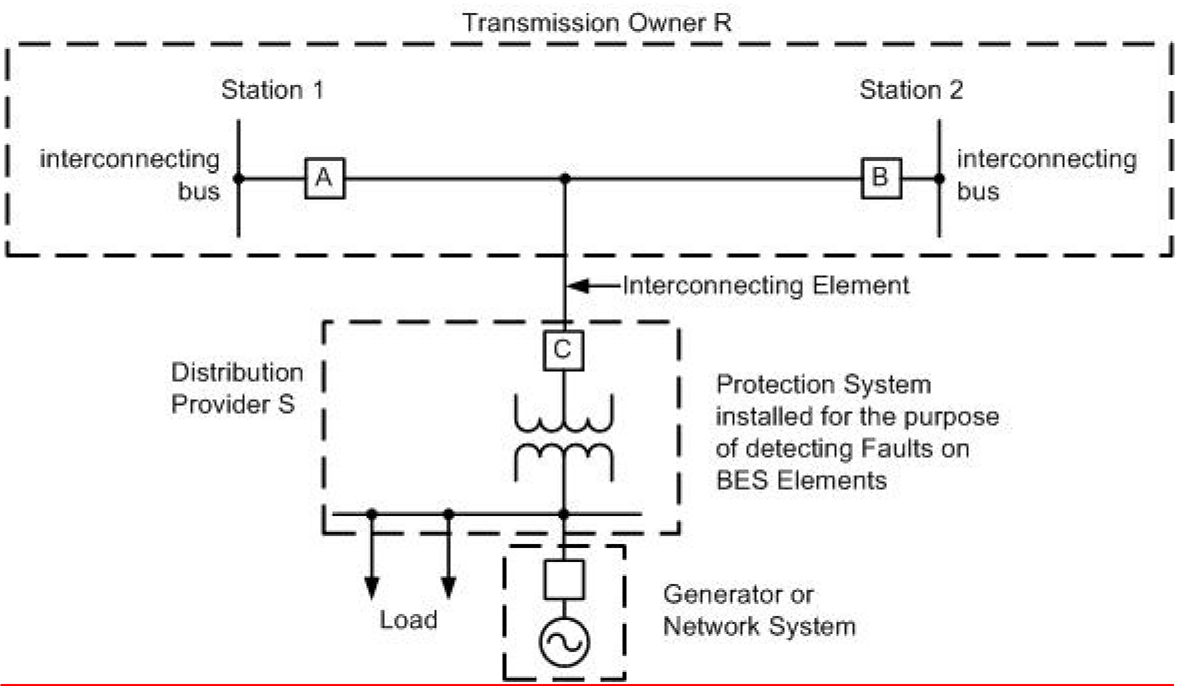
In Figure 2 above, the ~~Interconnected~~Interconnecting Element between the Transmission Owner and the Generator Owner is the transmission line or bus between Breakers A and C.

Note: Depending on the actual configuration and/or ownership, Breaker A may, or may not, exist as a GSU unit high-side breaker or a line breaker.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 2, Owner R is to develop ~~proposed~~ Protection System settings associated with Breaker A. Transmission Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, Owner S is to develop ~~proposed~~ Protection System settings associated with Breaker C. ~~Generation~~ Generator Owner R is to review the Protection System settings associated with Breaker C (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

Figure 3





In Figure 3 above, the ~~Interconnected~~Interconnecting Element between the Transmission Owner and the Distribution Provider is the transmission line (or tap) between the Distribution Provider's Breaker C and the point of connection to the line between the Transmission Owner's Breakers A and B. Therefore, the applicable Protection Systems per this standard are those at Breakers A, B and C.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 3, Distribution Provider S is to develop ~~proposed~~ Protection System settings associated with Breaker C. Transmission Owner R is to review the Protection System settings associated with

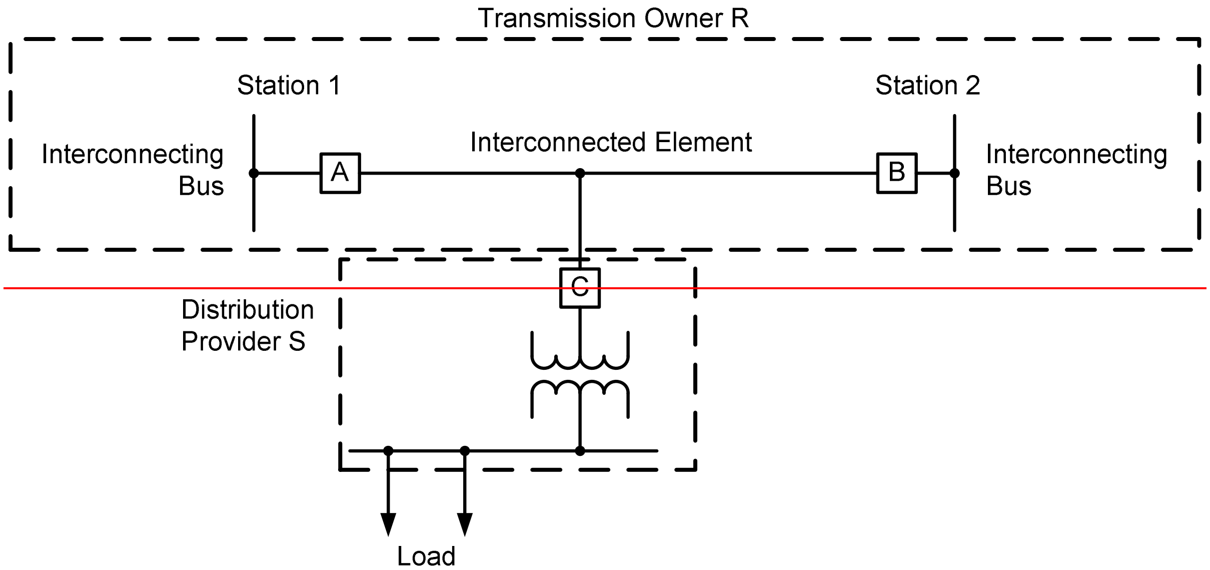
Line Breaker C (provided by Distribution Provider S) for coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2.

Notes:

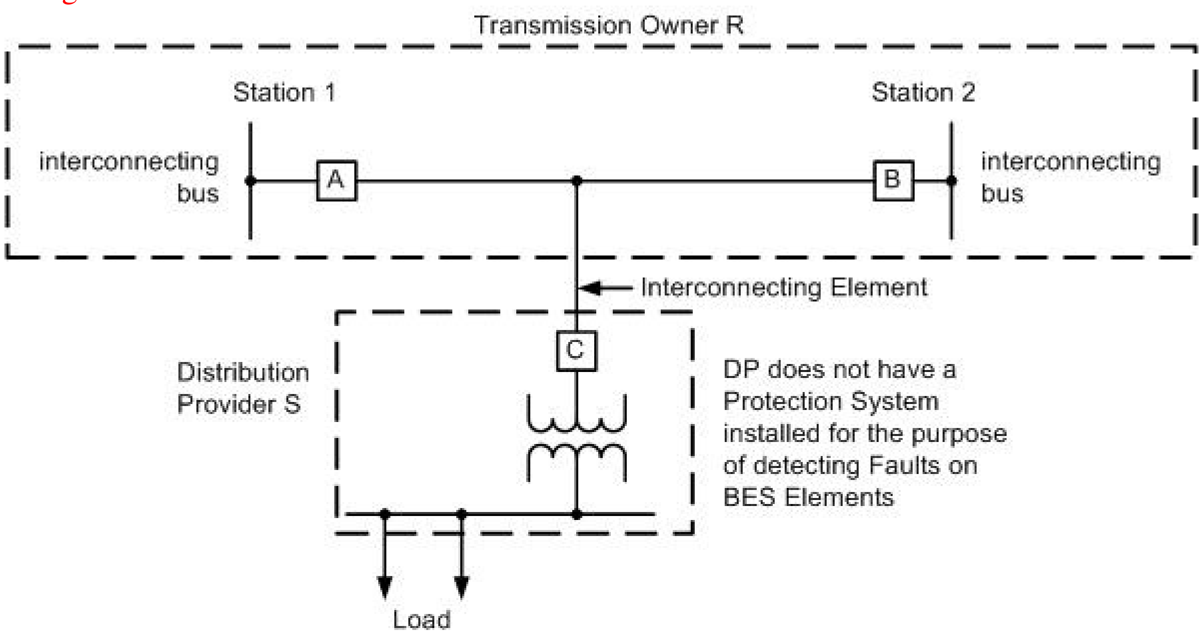
A PSCS is required per this standard for this example if a Protection System at the Distribution Provider's substation is installed for the purpose of detecting Faults on BES Elements.

Protection Systems installed for the purpose of detecting Faults on BES Elements do not include relays that, though they may operate for such Faults, are not installed specifically for that purpose. As an example, reverse power relays are often installed to detect situations where the transmission source for a power transformer becomes de-energized (for whatever reason) while the distribution bank remains energized from a source on the low-voltage side. In this case, the settings of the reverse power relay are typically calculated based on the charging current of the transformer from the low-voltage side. Although relays installed and set in this manner may operate as a result of a Fault on a BES Element, they are not specifically installed for the purpose of detecting that Fault.

Figure 4



~~In Figure 4~~



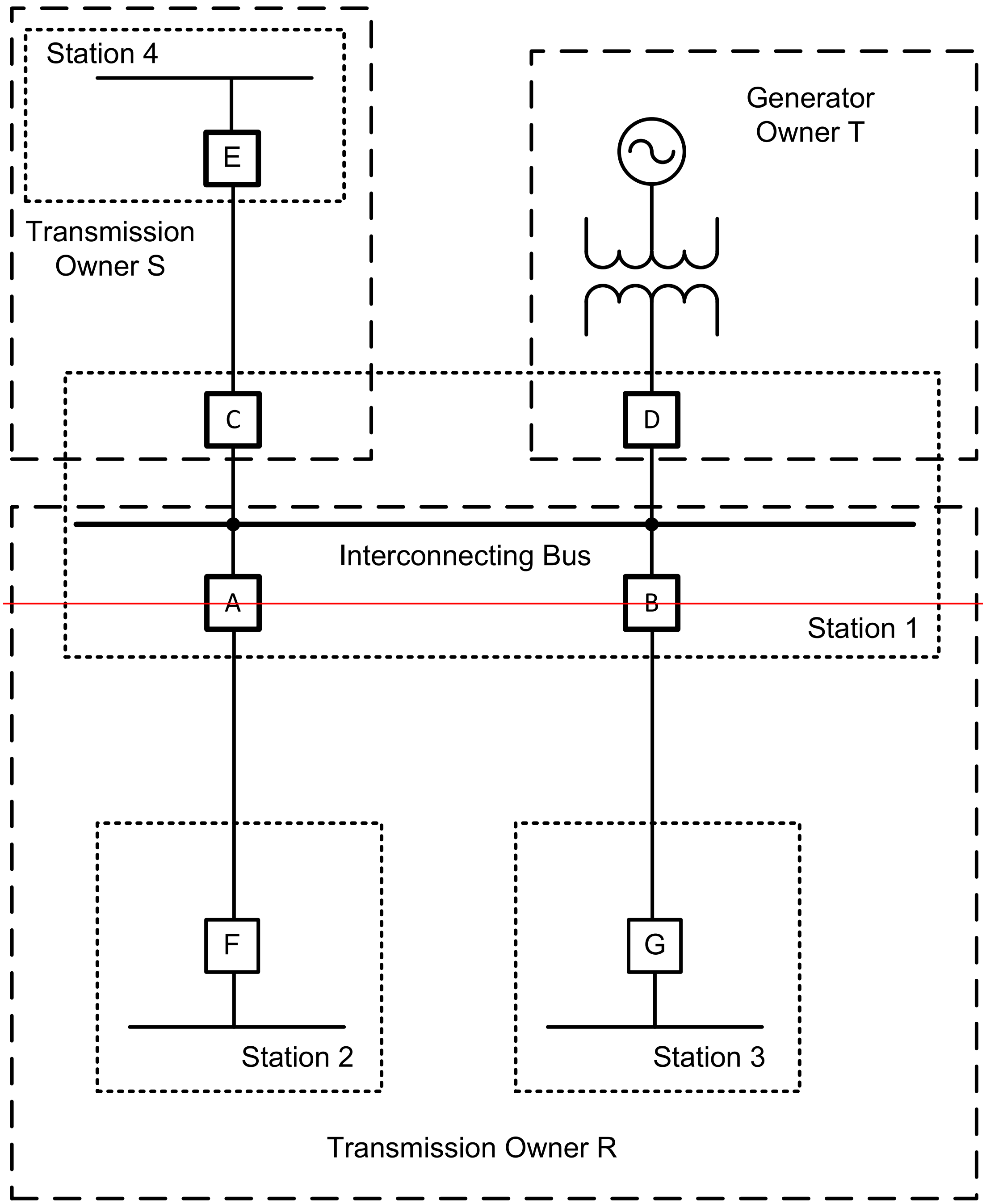
The configuration above~~, the Interconnected Element between the Transmission Owner and~~ is an example excluded from this standard because the Distribution Provider ~~is the transmission line or tap between the line and Breaker C.~~

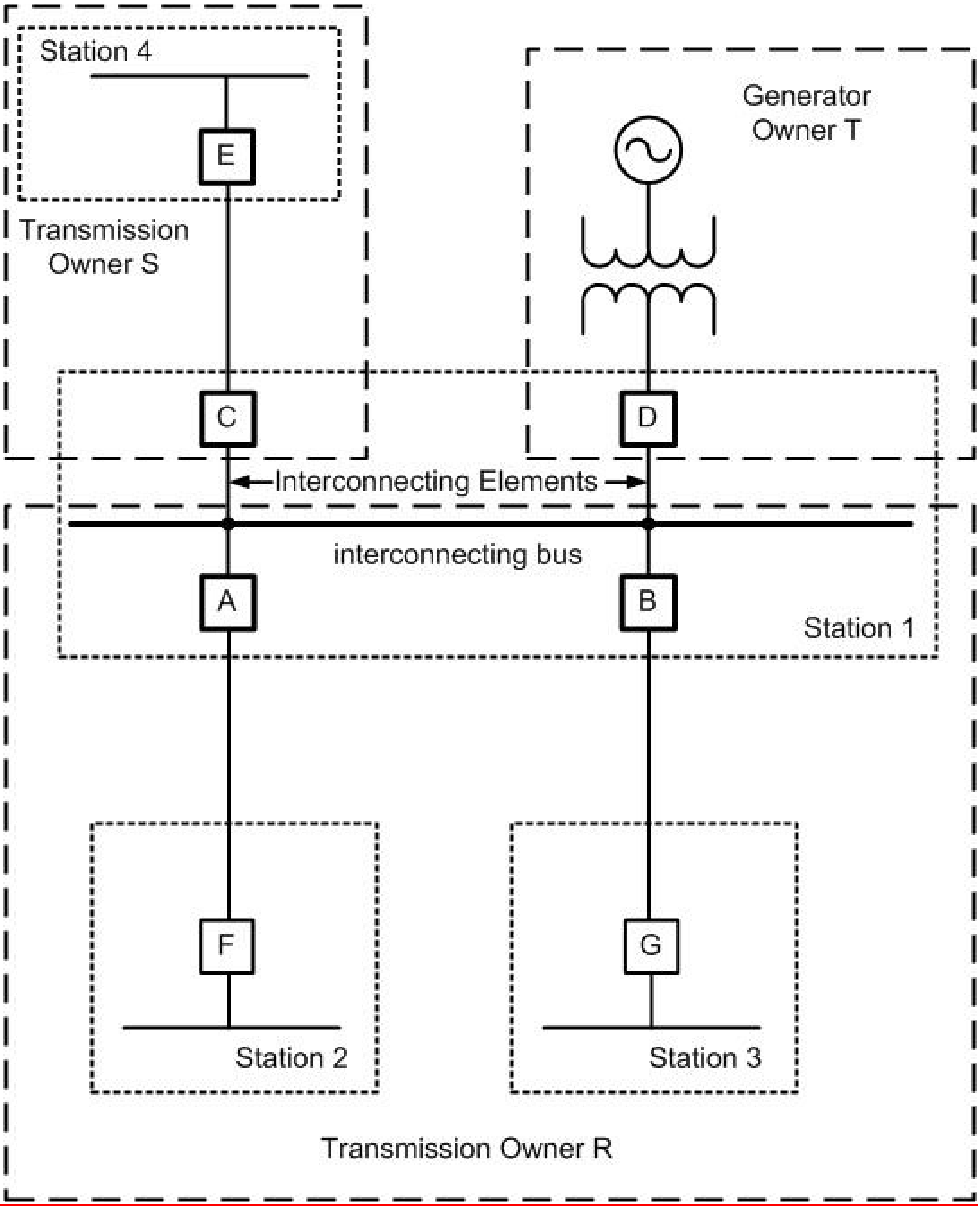
~~**Note:** No specific PSCS is required per this standard for this example since the~~S does not own Protection ~~System at the Distribution Provider's substation is not~~Systems installed for the purpose of detecting Faults on BES Elements.

Figure 5

Transmission/Generation Facility with Multiple Owners

Note: In a large majority of cases, Figure 2 would be applicable for most generator interconnections. In Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T.





~~In~~ Figure 5 above~~,~~ illustrates the ~~Interconnected Element~~Interconnecting Elements between the Transmission Owners R and S and Generator Owner T~~ is the common Transmission bus.~~. In this example, Transmission Owner S and Generator Owner T are not directly ~~interconnected~~interconnecting to each other at Station 1. All direct interconnections are between Owner R and each of the other Owners connected to the common bus at Station 1.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 5:

Owner S is to develop ~~proposed~~ Protection System settings associated with Breakers C and E.

Owner T is to develop ~~proposed~~ Protection System settings associated with Breaker D, the generator, and its associated equipment.

Owner R is to develop ~~proposed~~ Protection System settings associated with Breakers A, B, F and G.

Owner R is to review the Protection System settings associated with Breaker C, E, D, and the generator Protection System (provided by Owners S and/or T) for coordination issues with the Protection System settings associated with Breakers A and B.

Owner S is to review the Protection System settings associated with Breakers A, F, B, G, D, and the generator Protection System (provided by Owners R and/or T) for coordination issues with the Protection System settings associated with Breaker C. To perform this review, it will be necessary that Transmission Owner R provide Owner S with its settings for Breakers A, F, B, and G, as well as the settings for Breaker D and generator Protection System settings provided to Owner R by Generator Owner T.

Owner T is to review the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R and/or S) for coordination issues with the Protection System settings associated with Breaker D or the generator Protection System. In order to perform this review, it will be necessary that Transmission Owner R provide Generator Owner T with its settings for Breakers A, F, G, and B, as well as the settings for Breaker C and E provided to Owner R by Transmission Owner S.

Implementation Plan

Project 2007-06 System Protection Coordination PRC-027-1

Approvals Requested

- PRC-027-1 Protection System Coordination for Performance During Faults

Retirements Requested

- PRC-001-2 System Protection Coordination, Requirements R2 and R3

Applicable Entities

Standard	Applicable Entities					
	TO	GO	DP	TOP	GOP	BA
PRC-027-1: Protection System Coordination for Performance During Faults	X	X	X			

Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definitions for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

Interconnecting Element: A BES Element that electrically joins facilities:
a) owned by separate Registered Entities, or
b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Transmission Owner, Generator Owner, or Distribution Provider)

Protection System Coordination Study: A study that documents existing or proposed Protection Systems operate in the intended sequence for clearing Faults.

Background

On December 7, 2006, the NERC Planning Committee approved the assessment of Standard PRC-001-1 (System Protection Coordination) prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF asserted:

> *"The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the 'operating horizon, operations planning horizon, and planning horizon' protection coordination issues, the deficiencies in the current standard are magnified."*

And further:

> *"The SPCTF… recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards."*

The Standard Committee approved the Standard Authorization Request with modifications by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

With the development of the proposed Reliability Standard PRC-027-1, the Standard Drafting Team (SDT) for Project 2007-06 – System Protection Coordination, has followed the observations and recommendation of the NERC SPCTF assessment of PRC-001-1 which had six requirements. The SDT accomplishes this by:

1. Incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) and moving those requirements into a new standard (as recommended by the SPCTF assessment), focusing on the performance of Protection Systems during Faults.
2. Assigning responsibility for coordination of Protection Systems during Faults to the appropriate functional entities – the Protection System equipment owners, specifically: Transmission Owners, Generator Owners, and Distribution Providers.
3. Transferring the responsibility of addressing the three operating horizon Requirements R2, R5, and R6 of PRC-001-1 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standard(s) within that project. (The NERC Board of Trustees approved these changes proposed by the Project 2007-03 team when it approved PRC-001-2 on May 9, 2012.)
4. Leaving the legacy Requirement R1 of PRC-001-2 until PER-005-2 — Operations Personnel Training is approved by the applicable regulatory authorities.

Effective Date of New or Revised Standards and Definitions

PRC-027-1 - Protection System Coordination for Performance During Faults

PRC-027-1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Effective Date for Definitions

The two proposed definitions (Interconnecting Facilities and Protection System Coordination Study) shall become effective at the same time as PRC-027-1.

Implementation Plan

Project 2007-06 System Protection Coordination
PRC-027-1

Approvals Requested

- PRC-027-1 Protection System Coordination for Performance During Faults

Retirements Requested

- PRC-001-2 System Protection Coordination, Requirements R2 and R3
- ~~PRC-001-3 System Protection Coordination~~

Applicable Entities

Standard	Applicable Entities					
	TO	GO	DP	TOP	GOP	BA
PRC-027-1: Protection System Coordination for Performance During Faults ~~PRC-001-3: System Protection Coordination~~	X	X	X	~~X~~	~~X~~	~~X~~

Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definitions for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

~~Interconnected~~ Interconnecting Element: A BES Element that electrically joins facilities ~~owned by~~:
a) owned by separate Registered Entities, or
b) owned by the same Registered Entity that represents multiple functional entity ~~r~~responsibilities
(Transmission Owner, Generator Owner, or Distribution Provider~~Distribution Provider, Generator Owner, or Transmission Owner~~)~~.~~

Protection System Coordination Study: A study that documents~~demonstrates~~ existing or proposed Protection Systems operate in the intended ~~desired~~ sequence for clearing Faults.

Background

On December 7, 2006, the NERC Planning Committee approved the assessment of Standard PRC-001-1 (System Protection Coordination) prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF asserted:

> *"The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the 'operating horizon, operations planning horizon, and planning horizon' protection coordination issues, the deficiencies in the current standard are magnified."*

And further:

> *"The SPCTF… recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards."*

The Standard Committee approved the Standard Authorization Request with modifications by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

With the development of the proposed Reliability Standard PRC-027-1, the Standard Drafting Team (SDT) for Project 2007-06 – System Protection Coordination, has followed the observations and recommendation of the NERC SPCTF assessment of PRC-001-1 which had six requirements. The SDT accomplishes this by:

1. Incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) and moving those requirements into a new standard (as recommended by the SPCTF assessment), focusing on the performance of Protection Systems during Faults.
2. Assigning responsibility for coordination of Protection Systems during Faults to the appropriate functional entities – the Protection System equipment owners, specifically: Transmission Owners, Generator Owners, and Distribution Providers.
3. Transferring the responsibility of addressing the three operating horizon Requirements R2, R5, and R6 of PRC-001-1 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standard(s) within that project. (The NERC Board of Trustees approved these changes proposed by the Project 2007-03 team when it approved PRC-001-2 on May 9, 2012.)
4. Leaving the legacy Requirement R1 of PRC-001-2 until PER-005-2 — Operations Personnel Training is approved by the applicable regulatory authorities~~of PRC-001-2 in PRC-001-3 (thereby not creating a reliability gap) until it is incorporated into a new or revised reliability standard~~.

~~Note: The drafting team added Measure (M1) to PRC-001-3 related to Requirement R1.~~

Effective Date of New or Revised Standards and Definitions

PRC-027-1 - Protection System Coordination for Performance During Faults

PRC-027-1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction~~PRC-027-1 shall become effective on the first day of the first calendar quarter that is 12 months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. For Interconnected Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date~~.

~~PRC-001-3 – System Protection Coordination~~

~~Same effective date as PRC-027-1.~~

Effective Date for Definitions

The two proposed definitions (~~Interconnected~~ Interconnecting Facilities and Protection System Coordination Study) shall become effective at the same time as PRC-027-1.

~~Retirement:~~

~~PRC-001-2 – Protection System Coordination shall be retired at midnight the day before PRC-001-3 becomes effective.~~

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Unofficial Comment Form

Project 2007-06 System Protection Coordination
4th Draft of PRC-027-1

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the 4th draft of the standard PRC-027-1: Protection System Coordination for Performance During Faults. Comments must be submitted by **8 p.m. Eastern November 1, 2013**. If you have questions please contact Al McMeekin or by telephone at 803-530-1963.

http://www.nerc.com/pa/Stand/Pages/Project-2007-06-System-Protection-Coordination.aspx

Background Information:
The Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted an initial draft of the Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPCSDT attempted to address the planning and non-operational issues identified in the assessment of PRC-001-1 performed by the NERC System Protection and Control Task Force (SPCTF) as well as the operating time frame issues identified in FERC Order 693. These operating time frame requirements involved detecting Protection System failures, informing operators and taking quick corrective actions; consequently, the SPCSDT transferred the Order 693 directives associated with Requirements R2, R5 and R6 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standards associated within that project. The Project 2007-03 drafting team retired Requirements R2, R5, and R6 of PRC-001-1 because they addressed data and data requirements that are now included in Reliability Standard TOP-003-2. The NERC Board of Trustees adopted Reliability Standards TOP-003-2 and PRC-001-2 on May 9, 2012.

The SPCSDT posted Draft 3 of PRC-027 in June, 2013 for comment and ballot. As part of that posting, the drafting team proposed revisions to PRC-001-2. The revisions were being proposed as an interim step to provide clarity to PRC-001 until it is retired. However, since this last posting, the informal initiative for revising PER-005-1 has transitioned to a formal project, Project 2010-01 Training. The proposed revisions to PER-005-1 address the reliability objective of PRC-001-2, Requirement 1. Proposed Reliability Standard PRC-027-1 incorporates the aspects of coordination in Requirements R2 and R3 of PRC-001-2. Consequently, NERC staff and the SPCSDT are recommending the retirement of PRC-001-2. As such the drafting team is no longer considering changes to PRC-001-2. The disposition of all three PRC-001-2 requirements is outlined in the Mapping Document associated with this project and is posted for stakeholder review. The retirement of PRC-001-2, Requirement R1 is contingent upon the successful ballot and approval of PER-005-2 by the applicable regulatory authorities. The retirement of PRC-001-2, Requirements R2 and R3 are predicated upon the successful ballot and approval of PRC-027-1 by the applicable regulatory authorities.

Based on comments received from industry stakeholders the drafting team made the following modifications to the draft standard:

- Changed the word ‘desired’ to ‘intended’ in the Purpose
- Changed the term ‘Interconnected Element’ to ‘Interconnecting Element’ throughout the standard
- Removed the technical justification for not conducting the Fault current review specified in Requirement R2
- Modified Requirement 4 and split it into two Requirements, R4 and R5 for clarity
- The Process Flow Chart was updated to reflect changes made to the standard
- The Figures and associated descriptions were modified to provide more clarity

The SPCSDT has responded to stakeholder comments and incorporated pertinent suggestions into the fourth draft of PRC-027-1 for stakeholder review and comment.

Questions

Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. Please provide any issues you have with this draft of PRC-027-1 along with a proposed solution.

Comments:

Project 2007-06 System Protection Coordination Mapping Document

Mapping Document Showing Translation of PRC-001-2 — System Protection Coordination to PRC-027-1 — Protection System Coordination for Performance During Faults and PER-005-2 — Operations Personnel Training.

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PER-005-2**
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	PER-005-2	PER-005-2 — Operations Personnel Training (entire standard)

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R2.1** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. **R2.2** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	PRC-027-1: R1, R2, R3, R4 & R5 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Coordination Study (PSCS) for each of its Interconnecting Elements as follows: **1.1.1.** Within 60 calendar months after the effective date of this standard, if no PSCS for that Interconnecting Element exists. **1.1.2.** Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. **1.1.3.** According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or technically justify why such a study is not required. **1.1.4.** Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3, or technically justify why such a study is not required. **1.2.** Within 90 calendar days after the completion of each PSCS or the technical justification pursuant to Requirement R1, Part 1.1, provide to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s): a summary of the results of each PSCS performed, including, at a minimum, the Protection Systems reviewed,

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		the associated Fault current(s) used, any issues identified, and any revisions or actions proposed; or the technical justification. **R2.** For each Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months: **2.1.** Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at its interconnecting bus where a PSCS is available pursuant to Requirement R1. **2.2.** Calculate the percent change between the Fault current values (single line to ground and 3-phase for its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation: $\% \, Change = \left\| \frac{Iscs - Ipscs}{Ipscs} \right\| x \, 100$ Where : I_{scs} = Fault current value from present short circuit study And: I_{pscs} = Fault current value used in the most recent PSCS **2.2.1** Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (Iscs) to each owner of the Protection System(s) associated with the Interconnecting Element. **R3.** Each Transmission Owner, Generator Owner, and Distribution

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnecting Element: **3.1.** Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s). • New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios • Changes to a transmission system Element that alter any sequence or mutual coupling impedance • Changes to generator unit(s) that result in a change in impedance • Changes to the generator step-up transformer(s) that result in a change in impedance **3.2.** Requested information related to the coordination of Protection Systems associated with an Interconnecting Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule. **3.3.** Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		activities, or emergency replacements made due to failures of Protection System components. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a summary of the results of a PSCS or a technical justification explaining why a PSCS is not required (pursuant to Requirement R1, Part 1.2) shall, within 90 calendar days after receipt or according to an agreed upon schedule, review the summary of the results or the technical justification, and respond to the other owner(s) either: • Confirming that the summary of the results was reviewed and no coordination issue(s) were identified, or • Confirming that the summary of the results was reviewed and any identified coordination issue(s) were noted, or • Confirming that a technical justification was reviewed and no issue(s) were identified, or • Confirming that a technical justification was reviewed and any identified issue(s) were noted **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a response pursuant to Requirement R4 shall address any identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element.
R3. Each Transmission Operator shall	PRC-027-1:	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	R1, R2, R3, R4 & R5 Note: Applicability changed to GO, TO and DP	shall: **1.1.** Perform a Protection System Coordination Study (PSCS) for each of its Interconnecting Elements as follows: **1.1.1.** Within 60 calendar months after the effective date of this standard, if no PSCS for that Interconnecting Element exists. **1.1.2.** Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. **1.1.3.** According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or technically justify why such a study is not required. **1.1.4.** Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3, or technically justify why such a study is not required. **1.2.** Within 90 calendar days after the completion of each PSCS or the technical justification pursuant to Requirement R1, Part 1.1, provide to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s): a summary of the results of each PSCS performed, including, at a minimum, the Protection Systems reviewed, the associated Fault current(s) used, any issues identified, and any

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		revisions or actions proposed; or the technical justification. **R2.** For each Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months: **2.1.** Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at its interconnecting bus(s) where a PSCS is available pursuant to Requirement R1. **2.2.** Calculate the percent change between the Fault current values (single line to ground and 3-phase for its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation: $$\% \, Change = \left\lvert \frac{Iscs - Ipscs}{Ipscs} \right\rvert x \; 100$$ Where : I_{scs} = Fault current value from present short circuit study And: I_{pscs} = Fault current value used in the most recent PSCS **2.2.1** Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (Iscs) to each owner of the Protection System(s) associated with the Interconnecting Element. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		Provider connected to the same Interconnecting Element: **3.1.** Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s). • New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios • Changes to a transmission system Element that alter any sequence or mutual coupling impedance • Changes to generator unit(s) that result in a change in impedance • Changes to the generator step-up transformer(s) that result in a change in impedance **3.2.** Requested information related to the coordination of Protection Systems associated with an Interconnecting Element within 30 calendar days of receiving a request or according to an agreed-upon schedule. **3.3.** Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		System components. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a summary of the results of a PSCS or a technical justification explaining why a PSCS is not required (pursuant to Requirement R1, Part 1.2) shall, within 90 calendar days after receipt or according to an agreed upon schedule, review the summary of the results or the technical justification, and respond to the other owner(s) either: • Confirming that the summary of the results was reviewed and no coordination issue(s) were identified, or • Confirming that the summary of the results was reviewed and any identified coordination issue(s) were noted, or • Confirming that a technical justification was reviewed and no issue(s) were identified, or • Confirming that a technical justification was reviewed and any identified issue(s) were noted **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a response pursuant to Requirement R4 shall address any identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element.

Project 2007-06 System Protection Coordination Mapping Document

Mapping Document Showing Translation of PRC-001-2 — System Protection Coordination to PRC-027-1 — Protection System Coordination for Performance During Faults and PER-005-2 — Operations Personnel Training.

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PER-005-2**
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	PER-005-2	PER-005-2 — Operations Personnel Training (entire standard)

~~Standard: PRC-001-2 - System Protection Coordination~~		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
~~**R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.~~	~~Retained~~	~~NA~~
R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R2.1** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. **R2.2** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	PRC-027-1~~,~~: R1, R2, R3, ~~&~~ R4 & R5 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Coordination Study (PSCS) for each of its ~~Interconnected Element on its System~~Interconnecting Elements as follows: **1.1.1.** Within 60 calendar months after the effective date of this standard, if no PSCS for that Interconnecting Element exists. **1.1.2.** Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. **1.1.3.** According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or ~~within~~technically justify why such a study is not required. **1.1.4.** Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3, or technically justify why such

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		a study is not required. **1.2.** Within 90 calendar days after the completion of each PSCS or the technical justification pursuant to Requirement R1, Part 1.1, provide to the other owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element(s~~),~~): a summary of the results of each PSCS performed ~~pursuant to Requirement R1, Part 1.1, (~~, including, at a minimum, the Protection Systems reviewed, the associated Fault ~~currents~~current(s) used, any issues identified, and any revisions or actions proposed~~).~~; or the technical justification. **R2.** For each Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months: **2.1.** Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at its interconnecting bus where a PSCS is available pursuant to Requirement R1. **2.2.** Calculate the percent change between the Fault current values (single line to ground and 3-phase for its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation: $\%\ Change = \left\lvert \frac{Iscs - Ipscs}{Ipscs} \right\rvert x\ 100$

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		Where : I_{scs} = Fault current value from present short circuit study And: I_{pscs} = Fault current value used in the most recent PSCS **2.2.1** Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (Iscs) to each owner of the Protection System(s) associated with the Interconnecting Element. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same ~~Interconnected~~Interconnecting Element: **3.1.** Details for any proposed change or addition listed below; either at an existing or new Facility associated with the ~~Interconnected~~Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the ~~Interconnected~~Interconnecting Element(s). • New installation, replacement with different types, or modification of~~:~~ protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios • Changes to a transmission system Element that alter any sequence or mutual coupling impedance

~~Standard: PRC-001-2 - System Protection Coordination~~		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		• Changes to generator unit(s) that result in a change in impedance • Changes to the generator step-up transformer(s) that result in a change in impedance **3.2.** Requested information related to the coordination of Protection Systems associated with an ~~Interconnected~~Interconnecting Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule. **3.3.** Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider ~~shall~~that received a summary of the results of a PSCS or a technical justification explaining why a PSCS is not required (pursuant to Requirement R1, Part 1.2) shall, within 90 calendar days after receipt or according to an agreed upon schedule, review the summary of the results or the technical justification, and respond to the other owner(s) either: • ~~**4.2.** Prior~~Confirming that the summary of the results was reviewed and no coordination issue(s) were identified, or • Confirming that the summary of the results was reviewed and any identified coordination issue(s) were noted, or

~~Standard: PRC-001-2 - System Protection Coordination~~		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		• Confirming that a technical justification was reviewed and no issue(s) were identified, or • Confirming that a technical justification was reviewed and any identified issue(s) were noted **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a response pursuant to Requirement R4 shall address any identified coordination issues prior to implementing any proposed change(s) or ~~modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted~~addition(s) to the Protection System(s) ~~changes including the resolution of any identified coordination issues~~associated with the Interconnecting Element.
R3. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	PRC-027-1~~,~~: R1, R2, R3, ~~&~~ R4 & R5 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Coordination Study (PSCS) for each of its ~~Interconnected Element on its System~~ Interconnecting Elements as follows: **1.1.1.** Within 60 calendar months after the effective date of this standard, if no PSCS for that ~~Interconnected~~Interconnecting Element exists. **1.1.2.** Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus,

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		as described in Requirement R2, or technically justify why such a study is not required. **1.**~~2. Within 90 calendar days after the completion of each PSCS provide to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s), a summary of the results of each PSCS performed pursuant to Requirement R1, Part 1.1, (including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed).~~**1.3.** According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or technically justify why such a study is not required. **1.1.4.** Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3, or technically justify why such a study is not required. **1.2.** Within 90 calendar days after the completion of each PSCS or the technical justification pursuant to Requirement R1, Part 1.1, provide to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s): a summary of the results of each PSCS performed, including, at a minimum, the Protection Systems reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed; or the technical justification. **R2.** For each ~~Interconnected~~Interconnecting Element on its System, the

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		Transmission Owner shall, once every 60 calendar months~~, technically justify why Fault current does not affect the Protection System coordination, or~~: **2.1.** Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at ~~the~~its interconnecting bus(s) where a ~~Protection System Coordination Study (~~PSCS~~)~~ is available ~~per~~pursuant to Requirement R1. **2.2.** Calculate the percent change between the Fault current values (single line to ground and 3-phase for ~~the~~its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation: $\% \ Change = \left\| \frac{Iscs - Ipscs}{Ipscs} \right\| x\ 100$ Where : I_{scs} = Fault current value from present short circuit study And: I_{pscs} = Fault current value used in the most recent PSCS **2.2.1** Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (Iscs) to each owner of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same ~~Interconnected~~Interconnecting Element:

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s). • New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios • Changes to a transmission system Element that alter any sequence or mutual coupling impedance • Changes to generator unit(s) that result in a change in impedance • Changes to the generator step-up transformer(s) that result in a change in impedance **3.2.** Requested information related to the coordination of Protection Systems associated with an ~~Interconnected~~Interconnecting Element within 30 calendar days of receiving a request or according to an agreed-upon schedule. **3.3.** Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		System components. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a summary of the results of a PSCS or a technical justification explaining why a PSCS is not required (pursuant to Requirement R1, Part 1.2) shall~~:~~ ~~**4.1.** Within~~, within 90 calendar days after receipt~~,~~ or according to an agreed upon schedule, review the summary of the results ~~of a PSCS (per Requirement R1, Part 1.2)~~or the technical justification, and respond to the other owner(s~~):~~) either: ~~• Accepting~~Confirming that the ~~results, or~~ • ~~• Rejecting~~summary of the results was reviewed and ~~suggesting modifications to resolve~~no coordination issue(s) were identified, or • Confirming that the summary of the results was reviewed and any identified coordination issue(s) were noted, or • Confirming that a technical justification was reviewed and no issue(s) were identified, or • Confirming that a technical justification was reviewed and any identified issue(s) were noted **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a response pursuant to Requirement R4 shall address any identified coordination issues prior to implementing any proposed change(s)

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		or addition(s) to the Protection System(s) associated with the Interconnecting Element.

Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 — Protection System Coordination for Performance During Faults

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1 — Protection System Coordination for Performance During Faults.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

The System Protection Coordination Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors
High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures; nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and, therefore, concentrated its approach on the reliability impact of the requirements.

PRC-027-1 Protection System Coordination for Performance During Faults is a new Reliability Standard with the stated purpose: "*To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.*" PRC-027-1 has five (5) requirements that incorporate and clarify the reliability intent of Requirements R2 and R3 of PRC-001-2. The new standard addresses the aspects of coordination for new and changes to existing Protection Systems, as well as requiring an initial and periodic review of existing Protection Systems. The new requirements describe the steps necessary to achieve coordination. The coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner, reviewing each others' Protection System settings and schemes, and resolving any identified coordination issues.

All five requirements are assigned VRFs of Medium. The assignment of the Medium VRFs was made based on the premise that failure to perform these coordination activities by themselves would not directly cause or contribute to bulk power system instability, separation, or a Cascading sequence of failures. For a requirement to be assigned a "High" VRF, there should be the expectation that failure to meet the required performance "will" result in instability, separation, or Cascading failures, and this is usually not the case when an applicable entity fails to 'coordinate' activities. While the SDT agrees that, under some circumstances, it is possible that a failure to perform the required activities may hinder the coordination process; however, the failure would not, by itself, result in instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a “binary” type requirement must be a “Severe” VSL.

Guideline 2b: Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-027-1, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to perform a Protection System Coordination Study for each Interconnecting Element to verify that Protection Systems components operate in the intended sequence during Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R1 is similar in scope to Requirements R2, R3, R4 and R5, as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R1 directs that Protection System Coordination Studies are performed for every Interconnecting Element to verify coordination of existing Protection Systems. This requirement is similar to Requirement R1 of FAC-002-1, which also requires studies be performed and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to perform a Protection System Coordination Study for each Interconnecting Element to verify that Protection Systems components operate in the intended sequence during Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R1 does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by less than or equal to	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to 20 calendar	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30 calendar	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required but was late by more than 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar days.

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
10 calendar days.	days.	days.	OR The responsible entity failed to perform a Protection System Coordination Study on an Interconnected Element in accordance with Requirement R1, Parts 1.1.1, 1.1.2, 1.1.3, or 1.1.4. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2, 1.1.3, or 1.1.4. OR The responsible entity failed to provide a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2.

VSL Justifications – PRC-027-1, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to periodically perform a short circuit study to calculate the percent change in Fault current values used as inputs for updating Protection System Coordination Study(s), and to provide the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s) updated Fault current values, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R2 is similar in scope to Requirements R1, R3, R4 and R5 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R2 facilitates a periodic review of Fault currents, and notification of owner(s) of the Protection System(s) associated with the Interconnecting Element(s). This requirement is similar to Requirement R6 of BAL-005-0.2b in that it also requires the comparison of calculated data and possible notification of other entities; and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to periodically perform a short circuit study to calculate the percent change in Fault current values used as inputs for updating Protection System Coordination Study(s), and to provide the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s) updated Fault current values, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R2 does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner performed a short circuit study, as required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days.	The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 90 calendar days. OR The Transmission Owner failed to perform a short circuit study, as required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent change between the Fault currents, according to the equation designated in Requirement R2, Part 2.2.
OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnected Element, the updated Fault current values, as required in Requirement R2, Part 2.2.1.

VSL Justifications – PRC-027-1, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to communicate proposed change(s) or addition(s) that modify the conditions used in the coordination of Protection System(s) associated with an Interconnecting Element or provide requested information needed to conduct a Protection System Coordination Study could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R3 is similar in scope to Requirements R1, R2, R4 and R5 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R3 facilitates the provision of pertinent information regarding proposed changes that could impact the coordination of Protection Systems associated with an Interconnecting Element, or information needed to do a Protection System Coordination Study. This requirement is similar to Requirement R8 of FAC-008-3 in that it also requires the provision of reliability data to other pertinent functional entities, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to communicate proposed change(s) or addition(s) that modify the conditions used in the coordination of Protection System(s) associated with an Interconnecting Element or provide requested information needed to conduct a Protection System Coordination Study could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R3 does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R3			
Lower	**Moderate**	**High**	**Severe**
			The responsible entity failed to provide the owner(s) of the Facility associated with the Interconnecting Element, details for any proposed change(s) or addition(s) identified in Requirement R3, Part 3.1. OR
The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 30 calendar days.
OR	OR	OR	OR
The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days.	The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the information required in Requirement R3, Part 3.3.

VSL Justifications – PRC-027-1, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to review a summary of the results of a PSCS or a technical justification and respond to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s) in a timely manner could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R4 is similar in scope to Requirements R1, R2, R3 and R5 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R4 mandates responsible entities review a Protection System Coordination Study summary or a technical justification to determine if there are any issue(s) associated with any proposed change(s) to the pertinent Protection System(s), and communicate those findings to the sender. This requirement is similar to Requirement R1 of FAC-002-1 in that it requires coordination and cooperation of assessments, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to review a summary of the results of a PSCS or a technical justification and respond to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s) in a timely manner could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R4 does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following receipt of the Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4.	The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following receipt of the Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4.	The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following receipt of the Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4.	The responsible entity responded in more than 120 calendar days following receipt of the Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4. OR The responsible entity failed to review the Protection System Coordination Study summary of the results, or the technical justification provided to them in accordance with Requirement R4. OR The responsible entity failed to respond to the other owner(s) in accordance with Requirement R4.

VSL Justifications – PRC-027-1, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R5 is similar in scope to Requirements R1, R2, R3 and R4 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R5 mandates responsible entities address any identified coordination issue(s) prior to implementation. This requirement is similar to Requirement R3 of PRC-023-2 in that it also requires agreement be obtained, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R5 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R5			
Lower	**Moderate**	**High**	**Severe**
			The responsible entity failed to address any identified coordination issue(s), prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) in accordance with Requirement R5.

VSL Justifications – PRC-027-1, R5	
NERC VSL Guidelines	Meets NERC's VSL Guidelines for a Severe VSL—This is a binary or "pass-fail" requirement. The responsible entity either 'addressed' or 'did not address' an identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The responsible entity either 'addressed' or 'did not address' an identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 — Protection System Coordination for Performance During Faults

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1 — Protection System Coordination for Performance During Faults.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

The System Protection Coordination Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures; nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and, therefore, concentrated its approach on the reliability impact of the requirements.

PRC-027-1 Protection System Coordination for Performance During Faults is a new Reliability Standard with the stated purpose: "*To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.*" PRC-027-1 has ~~four (4~~five (5) requirements that incorporate and clarify the reliability intent of Requirements R2 and R3 of PRC-001-2. The new standard addresses the aspects of coordination for new and changes to existing Protection Systems, as well as requiring an initial and periodic review of existing Protection Systems. The new requirements describe the steps necessary to achieve coordination. The coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner, reviewing each others' Protection System settings and schemes, and resolving any identified coordination issues.

All ~~four~~five requirements are assigned VRFs of Medium. The assignment of the Medium VRFs was made based on the premise that failure to perform these coordination activities by themselves would not directly cause or contribute to bulk power system instability, separation, or a Cascading sequence of failures. For a requirement to be assigned a "High" VRF, there should be the expectation that failure to meet the required performance "will" result in instability, separation, or Cascading failures, and this is usually not the case when an applicable entity fails to 'coordinate' activities. While the SDT agrees that, under some circumstances, it is possible that a failure to perform the required activities may hinder the coordination process; however, the failure would not, by itself, result in instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-027-1, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to perform a Protection System Coordination Study for each Interconnect~~ed~~ing Element to verify that Protection Systems components operate in the ~~desired~~intended sequence during Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R1 is similar in scope to Requirements R2, R3, R4 and ~~R4~~R5, as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R1 directs that Protection System Coordination Studies are performed for every Interconnect~~ed~~ing Element to verify coordination of existing Protection Systems. This requirement is similar to Requirement R1 of FAC-002-1, which also requires studies be performed and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to perform a Protection System Coordination Study for each ~~Interconnected Facility~~Interconnecting Element to verify that Protection Systems components operate in the ~~desired~~intended sequence during Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R1 ~~addresses a single objective and has a single VRF.~~does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed a Protection System Coordination Study on an Interconnect~~ed~~ing Element as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance with Requirement R1, Part 1.2, but was late by less than or equal to	The responsible entity performed a Protection System Coordination Study on an Interconnect~~ed~~ing Element as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or	The responsible entity performed a Protection System Coordination Study on an Interconnect~~ed~~ing Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 20 calendar days but less than or	The responsible entity performed a Protection System Coordination Study on an Interconnect~~ed~~ing Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required but was late by more than 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
10 calendar days.	equal to 20 calendar days.	equal to 30 calendar days.	days. OR The responsible entity failed to perform a Protection System Coordination Study on an Interconnected Element in accordance with Requirement R1, Parts 1.1.1, 1.1.2, 1.1.3, or 1.1.~~3~~4. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2, 1.1.3, or 1.1.~~3~~4. OR The responsible entity failed to provide a summary of the results of each Protection System Coordination Study ~~results~~ or a technical justification in accordance with Requirement R1, Part 1.2.

VSL Justifications – PRC-027-1, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to periodically ~~justify why Fault current does not affect the Protection System coordination; or~~ perform a short circuit study~~,~~ to calculate the percent change in Fault current values used as inputs for updating Protection System Coordination Study(s), and to provide ~~each~~the other owner(s) of the Protection System(s) associated with the Interconnect~~ed~~ing Element ~~of requisite changes in~~(s) updated Fault ~~currents~~current values, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R2 is similar in scope to Requirements R1, R3, R4 and ~~R4,~~R5 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R2 facilitates a periodic review of ~~technical justifications or~~ Fault currents, and notification of owner(s) of the Protection System(s) associated with the Interconnect~~ed~~ing Element(s). This requirement is similar to Requirement R6 of BAL-005-0.2b in that it also requires the comparison of calculated data and possible notification of other entities; and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to periodically ~~justify why Fault current does not affect Protection System Coordination; or~~ perform a short circuit study~~,~~ to calculate the percent change in Fault current values used as inputs for updating Protection System Coordination Study(s~~)~~), and to provide ~~each~~the other owner(s) of the Protection System(s) associated with the Interconnect~~ed~~ing Element ~~of requisite deviations in~~(s) updated Fault ~~currents~~current values, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System~~,~~ regardless of the situation. ~~Therefore, this Violation Risk Factor level conforms to~~ This requirement meets NERC's ~~definition of~~criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:

	PRC-027-1, Requirement R2 ~~addresses a single objective and has a single VRF.~~does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R2			
Lower	**Moderate**	**High**	**Severe**
~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by less than or equal to 30 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study, as required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days. OR The Transmission Owner provided the owner(s) of the Facility	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 30 calendar days but less than or equal to 60 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 60 calendar days but less than or equal to 90 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 90 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 90 calendar days. OR The Transmission Owner failed to perform a short circuit study, as required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent change between the Fault currents, according to the equation designated in Requirement R2, Part 2.2. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnect~~ed~~ing Element, the changes in Fault currents, as required in Requirement R2, Part

Proposed VSLs for PRC-027-1, R2			
Lower	**Moderate**	**High**	**Severe**
associated with the Interconnect~~ed~~ing Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	Interconnect~~ed~~ing Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	Interconnect~~ed~~ing Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnected Element, the updated Fault current values, as required in Requirement R2, Part 2.2.1.

VSL Justifications – PRC-027-1, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to communicate proposed ~~changes~~change(s) or addition(s) that modify the conditions used in the coordination of Protection ~~Systems~~System(s) associated with an Interconnect~~ed~~ing Element or provide requested information needed to conduct a Protection System Coordination Study could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R3 is similar in scope to Requirements R1, R2, R4 and ~~R4~~R5 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R3 facilitates the provision of pertinent information regarding proposed changes that could impact the coordination of Protection Systems associated with an Interconnect~~ed~~ing Element, or information needed to do a Protection System Coordination Study. This requirement is similar to Requirement ~~R2~~R8 of FAC-~~009-1~~008-3 in that it also requires the provision of reliability data to other pertinent functional entities, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to communicate proposed ~~changes~~change(s) or addition(s) that modify the conditions used in the coordination of Protection ~~Systems~~System(s) associated with an Interconnect~~ed~~ing Element or provide requested information needed to conduct a Protection System Coordination Study could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. ~~Therefore, this Violation Risk Factor level conforms to~~This requirement meets NERC's ~~definition of~~criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R3 ~~addresses a single objective and has a single VRF.~~does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R3			
Lower	**Moderate**	**High**	**Severe**
			The responsible entity failed to provide the owner(s) of the Facility associated with the Interconnect~~ed~~ing Element, details for any proposed change(s) or addition(s) identified in Requirement R3, Part 3.1. OR
The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 30 calendar days.
OR	OR	OR	OR
The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days.	The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the information required in Requirement R3, Part 3.3.

VSL Justifications – PRC-027-1, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to ~~communicate~~review a summary of the results of a PSCS or a technical justification and ~~cooperate with~~ respond to the other ~~owners~~owner(s) of the Protection System(s) ~~to resolve coordination issues~~ associated with ~~an Interconnected~~the Interconnecting Element(s) in a timely manner could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R4 is similar in scope to Requirements R1, R2, R3 and ~~R3~~R5 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R4 mandates responsible entities ~~affirm acceptance on~~ review a Protection System Coordination Study ~~results~~summary or a technical justification to determine if there are any issue(s) associated with any proposed ~~changes~~change(s) to the pertinent Protection System(s~~) prior to implementation.~~), and communicate those findings to the sender. This requirement is similar to Requirement ~~R2~~R1 of ~~PRC-023~~FAC-002-1 in that it ~~also~~ requires ~~agreement be obtained~~coordination and cooperation of assessments, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to ~~communicate~~review a summary of the results of a PSCS or a technical justification and ~~cooperate with~~ respond to the other ~~owners~~owner(s) of the Protection System(s) ~~to resolve coordination issues~~ associated with ~~an Interconnected~~the Interconnecting Element(s) in a timely manner could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R4 ~~addresses a single objective and has a single~~

VRF Justifications – PRC-027-1, R4		
		~~VRF.~~does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1~~.	The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1~~.	The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1~~.	The responsible entity responded in more than 120 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1~~. OR The responsible entity failed to review the ~~summary results of the~~ Protection System Coordination Study summary of the results, or the technical justification provided to them in accordance with Requirement R4~~, Part 4.1~~. OR The responsible entity failed to respond to the other ~~owners~~owner(s) in accordance with Requirement R4~~, Part 4.1.~~ ~~OR~~ ~~The responsible entity failed to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element accepted the Protection System(s) changes~~

Proposed VSLs for PRC-027-1, R4			
Lower	Moderate	High	Severe
			~~including the resolution of any identified coordination issues, prior to implementation of those changes, as required in Requirement R4, Part 4.2~~.

VSL Justifications – PRC-027-1, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R5	
Proposed VRF	Medium
NERC VRF Discussion	Failure to address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R5 is similar in scope to Requirements R1, R2, R3 and R4 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R5 mandates responsible entities address any identified coordination issue(s) prior to implementation. This requirement is similar to Requirement R3 of PRC-023-2 in that it also requires agreement be obtained, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R5 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R5			
Lower	Moderate	High	Severe
			The responsible entity failed to address any identified coordination issue(s), prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) in accordance with Requirement R5.

VSL Justifications – PRC-027-1, R5	
NERC VSL Guidelines	Meets NERC's VSL Guidelines for a Severe VSL—This is a binary or "pass-fail" requirement. The responsible entity either 'addressed' or 'did not address' an identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The responsible entity either 'addressed' or 'did not address' an identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Comment Period Closed

PRC-027-1 – Protection System Coordination for Performance During Faults had initially been posted for a 45-day formal comment period on September 18, 2013 with a ballot scheduled for the last ten days of the comment period.

After NERC staff review and discussion with the chairs of Project 2007-06 System Protection Coordination and Project 2010-01 Training, it was determined that the disposition of PRC-001-2 Requirement R1 was outside the scope of the SAR of either project. Therefore, NERC staff has decided to initiate informal development on a new draft SAR that will take a holistic approach to training by combining various training requirements located throughout the set of NERC Reliability Standards (including PRC-001-2 Requirement R1) into a new PER standard. The posting of PRC-027-1 will be removed from comment and ballot and the associated documents will be modified to reflect this direction. The System Protection Coordination Standard Drafting Team expects to repost the documents next week for a 45-day comment period with a ballot period open the last ten days of the posting.

Background information for this project can be found on the project page.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Comment Period: September 18, 2013 – November 1, 2013

Upcoming:
Additional Ballot and Non-Binding Poll for PRC-027-1: October 23, 2013 – November 1, 2013

Now Available

A 45-day comment period is open for draft 4 of **PRC-027-1** – Protection System Coordination for Performance During Faults through **8 p.m. Eastern on Friday, November 1, 2013**.

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period for **PRC-027-1** is open through **8 p.m. Eastern on Friday, November 1, 2013.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot of **PRC-027-1** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted from October 23, 2013 through November 1, 2013.

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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Draft 1 of SAR posted for comment June 11, 2007 – July 10, 2007.
2. SAR approved on August 13, 2007.
3. First posting of revised standard PRC-001-2 on September 11, 2009.
4. Transitioned from a revision of PRC-001-1 to development of PRC-027-1 based on industry comments, Quality Review feedback, and consideration of FERC directives relative to the existing requirements of PRC-001-1.
5. Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012.
6. Draft 2 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from November 16 – December 17, 2012.
7. Draft 3 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from June 4 – July 3, 2013.
8. Draft 4 of PRC-027-1 was posted for a 45-day formal comment and ballot from September 18 – November 1, 2013. Note: Posting and ballot postponed as of September 27, 2013.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: “To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.” This standard incorporates and clarifies the coordination aspects of Requirements R2 and R3 from PRC-001-2. The SPCSDT is soliciting stakeholder feedback on draft 4 of PRC-027-1 during a 45-day formal comment period with parallel ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Ballot	November - December 2013
Final Ballot	March 2014
BOT Adoption	May 2014

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2007-06 – PRC-027-1	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here.

The following terms are defined for use only within PRC-027-1:

Interconnecting Element
A Bulk Electric System (BES) Element that electrically joins Facilities:
a) owned by separate Registered Entities, or
b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Transmission Owner, Generator Owner, or Distribution Provider)

Protection System Coordination Study
A study documenting that existing or proposed Protection Systems operate in the intended sequence for clearing Faults.

Other Aspects of Coordination of Protection Systems Addressed by Other Projects:

Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects:

• Underfrequency Load shedding programs are addressed in PRC-006-1. Generator performance during frequency excursions is being addressed in PRC-024-1 by Project 2007-09 Generator Verification.

• Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed in PRC-024-1 by Project 2007-09, Generator Verification.

- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-1 by Project 2007-09.
- Transmission relay loadability is addressed in PRC-023-2.
- Generator relay loadability is addressed in PRC-025-1 by Project 2010-13.2, Phase 2 of Relay Loadability: Generation.
- Protective relay response during power swings will be addressed by Project 2010-13.3, Phase 3 of Relay Loadability: Stable Power Swings.
- Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and are addressed in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

The SPCSDT contends that including these other aspects of protection coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Coordination for Performance During Faults**
2. **Number:** PRC-027-1
3. **Purpose:** To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Generator Owner

4.1.3 Distribution Provider (that own Protection Systems identified in the Facilities section 4.2 below)

4.2 Facilities:

Protection Systems:

a) installed for the purpose of detecting Faults on Interconnecting Elements, and

b) that require coordination for isolating those faulted Elements

5. **Background:**

On December 7, 2006, the NERC Planning Committee approved the assessment of Reliability Standard PRC-001 – System Protection Coordination, prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF noted problems with the applicability to entities and vagueness of requirements in the existing PRC-001-1 reliability standard. The SPCTF concluded that the deficiencies of Reliability Standard PRC-001-1 were magnified by having requirements that addressed coordination of protection functions and capabilities in the operating and planning timeframes. Consequently, the SPCTF recommended that the requirements for the operating horizon and planning horizon be clearly delineated, and possibly divided into two standards.

The NERC Standards Committee approved a Standard Authorization Request that included the modifications noted by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPCSDT) posted an initial draft of Reliability Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPCSDT attempted to address all issues identified by the SPCTF assessment of PRC-001-1. The SPCSDT responded to the comments from the initial posting of PRC-001-2, and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC Quality Review (QR) in December 2010. Based on the results from the QR, and after informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to follow the SPCTF recommendation and focused their knowledge and expertise on developing a new results-based standard, concentrating on the reliability aspects (the coordination of new and existing protective systems in the planning horizon) associated with Requirements R3 and R4 of PRC-001-1. These aspects of coordination are incorporated and clarified in the proposed Reliability Standard PRC-027-1 – Protection System Coordination for Performance During Faults with the stated purpose:

> *"To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults."*

PRC-001-1 contained a non-specific training requirement (Requirement R1), three operating time frame requirements (Requirements R2, R5 and R6), and two planning requirements (Requirements R3 and R4). The SPCSDT transferred the responsibility of addressing the operating Requirements R2, R5, and R6 to the drafting team for Project 2007-03 Real-time Operations, charged with revising the TOP group of reliability standards. The Project 2007-03 drafting team retired Requirements R2, R5, and R6 of PRC-001-1 because they addressed data and data requirements that are now included in Reliability Standard TOP-003-2. The NERC Board of Trustees adopted Reliability Standards TOP-003-2 and PRC-001-2 on May 9, 2012.

Proposed Reliability Standard PRC-027-1 incorporates the aspects of coordination found in Requirements R2 and R3 of PRC-001-2. With the reliability intent of these two legacy requirements being addressed in PRC-027-1, it is necessary to retire them from PRC-001-2.

B. Requirements and Measures

Rationale for R1:

Part 1.1 A Protection System Coordination Study (PSCS) is necessary to verify coordination of Protection Systems for existing and new Interconnecting Elements. The drafting team defines the term “Interconnecting Element” as “A BES Element that electrically joins Facilities: a) owned by separate Registered Entities, or b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).”

Part 1.1.1 The drafting team contends 60 calendar months is an appropriate period of time for entities to perform the PSCS required where no study exists. The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnecting Elements that warrants a shorter time frame.

Part 1.1.2 The drafting team contends that 12 calendar months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater Fault current change at an interconnecting bus, where such conditions may warrant a new PSCS, or to technically justify why no such study is required. Refer to the Application Guidelines for Requirement R1 for examples of Protection Systems where technical justifications may be used.

Part 1.1.3 The drafting team contends that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, Part 3.1, or to technically justify why no such study is needed. The drafting team contends the timeframe associated with the requirement for any proposed changes or additions is contingent upon the project’s scope and schedule. Specifying a time frame for performing studies is unnecessary because notification of such a change may occur weeks or years prior to the change. The initiating entity has the incentive to provide the identified information as soon as possible to ensure timely implementations.

Part 1.1.4 The drafting team contends that entities must perform the studies required when notified of changes identified in Requirement R3, Part 3.3, or to technically justify why no such study is needed. The drafting team contends that six months is an appropriate period of time for entities to perform the studies required or to technically justify why no such study is needed when details of changes are provided associated with Requirement R3 Part 3.3.

Part 1.2 The drafting team contends to properly ensure coordination of Protection Systems associated with Interconnecting Element(s), all entities need to share the summary of results of a PSCS and assess the study results. The drafting team contends that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS performed in accordance with Requirement R1, Part 1.1 to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s).

Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

1.1. Perform a Protection System Coordination Study (PSCS) for each of its Interconnecting Elements as follows:

1.1.1 Within 60 calendar months after the effective date of this standard, if no PSCS for that Interconnecting Element exists.

1.1.2 Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required.

1.1.3 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or technically justify why such a study is not required.

1.1.4 Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3, or technically justify why such a study is not required.

1.2. Within 90 calendar days after the completion of each PSCS or the technical justification pursuant to Requirement R1, Part 1.1, provide to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s): a summary of the results of each PSCS performed, including, at a minimum, the Protection Systems reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed; or the technical justification.

M1. Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1, 1.1.2, 1.1.3, and 1.1.4 is a dated PSCS, or the summary of the results of each PSCS (hard copy or electronic file formats) demonstrating the time frames specified or agreed to in Parts 1.1.1, 1.1.2, 1.1.3, and 1.1.4 were achieved. Acceptable evidence of a technical justification for not performing a PSCS as specified in Parts 1.1.2, 1.1.3, and 1.1.4 may include, but is not limited to, documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any aspect of coordination.

M2. Acceptable evidence for Requirement R1, Part 1.2 is dated documentation demonstrating that the summary of the results of each PSCS or the technical justification (hard copy or electronic file formats) were provided within the specified time frame to the owner(s) of the Protection System(s) associated with the Interconnecting Element(s).

Rationale for R2: This requires a periodic review of Fault currents at the interconnecting bus and providing the results to the applicable entities when changes occur that meet the criteria of Requirement R2. It is important that interconnecting Facility owners are kept aware of changes that could affect proper performance of their Protection Systems. The Transmission Owner is identified as the entity responsible for performing the short circuit studies because they maintain the data necessary to perform the studies. Note: short circuit studies are used to determine the Fault current values at the interconnecting bus where a PSCS exists. These studies are typically performed assuming maximum generation and all Facilities in service.

The drafting team contends 60 calendar months provides the entities flexibility to schedule and perform the activities specified in Requirement R2, Parts 2.1 and 2.2.

Part 2.1 The drafting team contends maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus are necessary quantities needed to review the coordination.

Part 2.2 The drafting team is including this equation to assure a consistent approach is used by each Transmission Owner when calculating the percent change in Fault current values.

Part 2.2.1 The drafting team contends the 30-calendar day time frame is reasonable for providing the Fault current information to the owner(s) of the Protection System(s) associated with the Interconnecting Element. The drafting team determined that a change in Fault current of 10% indicates an appropriate point at which to provide this information, based on the fact that Protection Systems are typically set with margins above 10%.

R2. For each Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

2.1. Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at its interconnecting bus(s) where a PSCS is available pursuant to Requirement R1.

2.2. Calculate the percent change between the Fault current values (single line to ground and 3-phase for its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation:

$$\%\,Change = \left|\frac{Iscs - Ipscs}{Ipscs}\right| x\ 100$$

Where: I_{scs} = Fault current value from present short circuit study

And: I_{pscs} = Fault current value used in the most recent PSCS

2.2.1 Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (I_{scs}) to each owner of the Protection System(s) associated with the Interconnecting Element(s).

M3. Acceptable evidence for Requirement R2, Parts 2.1 and 2.2 is dated documentation (hard copy or electronic file formats) that contains the present Fault current values from the short circuit study for each interconnecting bus analyzed, and identifies the percent change from the Fault current values used in the most recent PSCS determined by the equation.

M4. Acceptable evidence for Requirement R2, Part 2.2.1 is dated documentation (hard copy or electronic file formats) that the updated Fault current values (I_{scs}), were provided within the specified timeframe to each owner of the Protection System associated with the Interconnecting Element.

Rationale for R3: This requires the transfer of appropriate information to the entities associated with each Interconnecting Element due to circumstances identified in Parts 3.1, 3.2, and 3.3.

Part 3.1 The reliability objective of this requirement is to enable the process of conducting PSCSs by ensuring that the information is provided to the owner(s) of the Protection Systems associated with Interconnecting Element(s). The drafting team contends that information about any proposed change or addition (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the Interconnecting Element. The drafting team contends that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list provided in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. Examples of changes to generator units that result in impedance changes could include replacements and re-ratings. This requirement also pertains to changes identified as a result of studies performed in Requirement 1, Part 1.1.

Part 3.2 The purpose of this requirement is to provide a means for an entity to receive the requested information in a timely manner in order to perform a PSCS, as required in Requirement 1, Parts 1.1.1, 1.1.2, 1.1.3, and 1.1.4. The drafting team contends 30 calendar days after receipt of the request is a sufficient amount of time to provide this information. The requirement also provides some flexibility for the parties involved to determine an otherwise agreed-to schedule, if appropriate.

Part 3.3 The drafting team contends 30 calendar days is sufficient time to provide the information.

Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that describes the information listed in Requirement R3, Parts 3.1 and 3.3 below is sufficient for use by all entities.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnecting Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s).

- New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios
- Changes to a transmission system Element that alter any sequence or mutual coupling impedance
- Changes to generator unit(s) that result in a change in impedance
- Changes to the generator step-up transformer(s) that result in a change in impedance

3.2. Requested information related to the coordination of Protection Systems associated with an Interconnecting Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule.

3.3. Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.

M5. Acceptable evidence for Requirement R3, Part 3.1 may include, but is not limited to, documentation (hard copy or electronic file formats) demonstrating that a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) as identified in the bulleted list, was provided to each responsible entity connected to the same Interconnecting Element.

M6. Acceptable evidence for Requirement R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was provided according to the agreed-upon schedule, or within 30 calendar days absent such an agreement.

M7. Acceptable evidence for Requirement R3, Part 3.3 is dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the permanent changes made was provided within 30 calendar days.

Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with Interconnecting Elements confirm that the Protection System(s) applied were reviewed and a response was provided to the other owner(s). The review assures that the owners of Protection Systems associated with the affected Interconnecting Element are aware of the changes and have responded with comments if necessary.

The drafting team contends 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with Interconnecting Elements to review the summary results of a PSCS or the technical justification and respond. Note: Pursuant to Requirement R1, Part 1.2, at a minimum, the summary of the results of a PSCS must include the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. The response should indicate the results of the PSCS or the technical justification were reviewed and, if applicable, any identified issues.

Note: The drafting team recognizes there could be situations where one owner may not agree with the other owner's protection philosophy but they can confirm that there were no identified coordination issues.

Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that describes the information listed in Requirement R3, Parts 3.1 and 3.3 is sufficient for use by all entities.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that received a summary of the results of a PSCS or a technical justification explaining why a PSCS is not required (pursuant to Requirement R1, Part 1.2) shall, within 90 calendar days after receipt or according to an agreed upon schedule, review the summary of the results or the technical justification, and respond to the other owner(s) either: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Confirming that the summary of the results was reviewed and no coordination issues were identified, or
- Confirming that the summary of the results was reviewed and any identified coordination issue(s) were noted, or

- Confirming that a technical justification was reviewed and no issue(s) were identified, or
- Confirming that a technical justification was reviewed and any identified issue(s) were noted

M8. Acceptable evidence for Requirement R4 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement.

Rationale for R5: This requirement obligates owner(s) of Protection System(s) associated with Interconnecting Elements to communicate and address any identified coordination issues prior to implementing the proposed Protection System(s) change(s) or addition(s); i.e., the in-service date of the Protection System(s).

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that received a response pursuant to Requirement R4 shall address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

M9. Acceptable evidence for Requirement R5 is dated documentation (hardcopy or electronic file formats) demonstrating that a response pursuant to Requirement R4 was received and that any identified coordination issues were addressed prior to implementation of any proposed Protection System(s) changes or additions.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System associated with an Interconnecting Element shall each keep data or evidence to show compliance with Requirements R1, R2, R3, R4, and R5, and Measures M1 through M9, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner or Distribution Provider that owns a Protection System at a Facility associated with an Interconnecting Element is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by less than or equal to 10	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or equal to 20	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 20 calendar days but less than or equal to 30	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required but was late by more than 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar days.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			calendar days.	calendar days.	calendar days.	OR The responsible entity failed to perform a Protection System Coordination Study on an Interconnecting Element in accordance with Requirement R1, Parts 1.1.1, 1.1.2, 1.1.3, or 1.1.4. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2, 1.1.3, or 1.1.4. OR The responsible entity failed to provide a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2.
R2	Operations Planning, Long-term Planning	Medium	The Transmission Owner performed a short circuit study, as required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days.	The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 90 calendar days. OR The Transmission Owner

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	failed to perform a short circuit study, as required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent change between the Fault currents, according to the equation designated in Requirement R2, Part 2.2. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnecting Element, the updated Fault current values, as required in Requirement R2, Part 2.2.1.
R3	Operations Planning, Long-term Planning	Medium				The responsible entity failed to provide the owner(s) of the Facility associated with the Interconnecting Element, details for any proposed

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	change or addition identified in Requirement R3, Part 3.1. OR The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the information required in Requirement R3, Part 3.3.
R4	Operations Planning, Long-term Planning	Medium	The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following receipt of the Protection System Coordination Study summary of the results or technical	The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following receipt of the Protection System Coordination Study summary of the results or technical	The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following receipt of the Protection System Coordination Study summary of the results or technical	The responsible entity responded in more than 120 calendar days following receipt of the Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			justification, as required in Requirement R4.	justification, as required in Requirement R4.	justification, as required in Requirement R4.	OR The responsible entity failed to review the Protection System Coordination Study summary of the results or the technical justification provided to them in accordance with Requirement R4. OR The responsible entity failed to respond to the other owners(s) in accordance with Requirement R4.
R5	Operations Planning, Long-term Planning	Medium				The responsible entity failed to address any identified coordination issue(s), prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) in accordance with Requirement R5.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Purpose:

To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.

This standard requires that separate Registered Entities communicate with each other to coordinate Protection System components on existing Interconnecting Elements; and communicate with each other prior to the energization of new or modified Protection Systems associated with Interconnecting Elements. The goal of the coordination is to verify that the Protection Systems intended for sensing Faults will operate in the intended sequence for internal and external Faults on the Interconnecting Element.

Requirement R1:

This requirement directs the applicable entities to perform a Protection System Coordination Study (PSCS) for every Interconnecting Element to verify coordination of existing Protection Systems where no recent study exists; or when Facility configuration changes are made, or where Fault current changes of 10% or more have occurred. In developing the language to define a PSCS, the System Protection Coordination Standard Drafting Team (SPCSDT) considered various reference books discussing protective relaying theory and application, along with the following description of "coordination of protection" from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Using the reference material cited above as guidance, the drafting team defined the term Protection System Coordination Study (PSCS) for use within the PRC-027-1 Reliability Standard as:

> "A study documenting that existing or proposed Protection Systems operate in the intended sequence for clearing Faults."

PSCSs comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in PSCSs include maximum generation with the transmission system under normal operating conditions and under single contingency conditions. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), and adequate directional polarizing quantities.

Part 1.1.1:

The drafting team contends applicable entities should have a documented PSCS for each Interconnecting Element to validate the Protection Systems associated with those Interconnecting Elements perform in a manner consistent with the purpose of this Standard. Additionally, the drafting team contends that 60 calendar months is an appropriate amount of time for entities to perform the initial studies expected under this requirement. This period considers the time some entities may require to create project scopes, acquire proposals, and secure contracts to hire external resources that may be needed to perform the studies. The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with Interconnecting Elements that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.

Part 1.1.2:

After notification of an identified 10% or greater change in Fault current (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1), the notified entities must perform a new PSCS of the Interconnecting Element or document why a study is not required. The drafting team recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater change in Fault current may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team contends the 12-calendar month time frame associated with this requirement represents a reasonable period to perform the studies that are required after identification by the 60-calendar month Fault current review.

Part 1.1.3:

After proposing or being notified of a change at a Facility associated with the Interconnecting Element, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the proposed or notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team contends the timeframe associated with performing a PSCS for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3, Part 3.1 is unnecessary because notification of such a change may occur weeks or years prior to the change due to the wide variety of conditions that may be associated with a particular change. The drafting team sees the entity initiating any change as having the incentive to move this along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R5.

Part 1.1.4:

After being notified of a change at a Facility associated with the Interconnecting Element associated with Requirement R3, Part 3.3, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team contends that six calendar months is an appropriate period of time for entities to perform the studies required, or to technically justify why no such study is needed.

Examples of Protection Systems where technical justifications may be used include:

1. Differential elements
2. Distance elements where infeed is not used in determining reach for the protection scheme.
3. Supervised overcurrent elements enabled by:
    - Loss of potential condition
    - Some communication assisted tripping
    - Switch-Onto-Fault (SOTF)
4. Reverse power, definite time &/or time overcurrent elements:
    - Designed to coordinate during maximum generation with the transmission system under normal operating conditions and under single contingency conditions regardless of Fault current.
    - Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.).

Requirement R1, Part 1.2 directs the entity performing the PSCS to provide a summary of the study results or a technical justification to the affected Interconnecting Element owner(s). The drafting team contends that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS it performed to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s). (Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that meets the requirements for a summary of the results of the PSCS would be sufficient for use by both Registered Entities.) The following inputs and results of a PSCS must be included in the summary provided pursuant to this requirement:

1. A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Facility, and which were reviewed for coordination of protective relays as part of the study, including the contingencies used in the evaluation.
2. A listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Facility under study.
3. A listing of any issues associated with the relay settings of the other owner(s) at the Facility that were identified by the study.
4. Any proposed revisions to a Protection System or its protective relay settings that were identified by the study.

Requirement R2:

The drafting team investigated various inputs that would trigger a review of the existing PSCSs and determined, through the experience of the drafting team members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated PSCS may be necessary. These variations could result from the accumulation of incremental changes over time. This requirement mandates the Transmission Owner perform a periodic review of Fault currents.

The short circuit study provides the Fault current values used to calculate the percent change between the most recent PSCS and the present Fault current values indicated by the short circuit study performed pursuant to Requirement R2, Part 2.1. This calculation is necessary to identify Fault current changes that must be communicated in accordance with Requirement R2, Part 2.2. Short circuit studies are typically performed assuming maximum generation and all Facilities in service.

The drafting team contends that 60 calendar months is an appropriate interval for reviewing Fault currents. The drafting team contends studies associated with changes that would affect the coordination in less than 60 calendar months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.2.1 further directs the Transmission Owner to, within 30 calendar days, inform each owner of the Facility associated with the Interconnecting Element when short circuit studies indicate that 10% changes in Fault current have occurred at the interconnecting bus(s). The drafting team contends the 30-calendar day time frame associated with this requirement is reasonable for providing the Fault current information to the interconnecting entity(s) and is consistent with other NERC reliability standards.

In Requirement R2, the Transmission Owner is identified as the functional entity responsible for performing the short circuit studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.

Requirement R3:

This directs the registered functional entity initiating any proposed change or addition to provide the details to the other affected entities of the Interconnecting Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes. Documentation provided to these other owners may include, but is not limited to, power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings. The recipient will incorporate the applicable information into its PSCSs to evaluate whether changes are required.

The list of applicable changes provided in Requirement R3, Part 3.1 is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. The drafting team recognizes that Facility changes at other locations can impact the PSCS of the Facility associated with the Interconnecting Element; e.g., the addition of a large autotransformer bank or generator not directly connected to the Interconnecting Element. The drafting team contends that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the drafting team sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule.

Requirement R3, Part 3.2 allows for entities to agree upon a schedule, appropriate to the circumstances, for providing the details needed to conduct a PSCS or, absent such agreement, within 30 calendar days of a request for this information. This requirement provides a means for entities to receive requested information in a timely manner. In consideration of circumstances where the information may not be readily available or may be incomplete due the retirement of personnel, the purging of records, change of ownership, etc., it also provides the flexibility of mutually agreeing to a schedule for exchanging information. The drafting team contends 30 calendar days after receipt of the request is a sufficient amount of time to provide the requested information where no other agreement exists.

Requirement R3, Part 3.3 includes a provision for providing details associated with changes to the previously agreed-upon coordination when permanent changes are made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components. Based upon the limited number of instances that would occur under such circumstances, the drafting team contends 30 calendar days after determining that changes are required is an appropriate time frame for providing the associated details to affected entities.

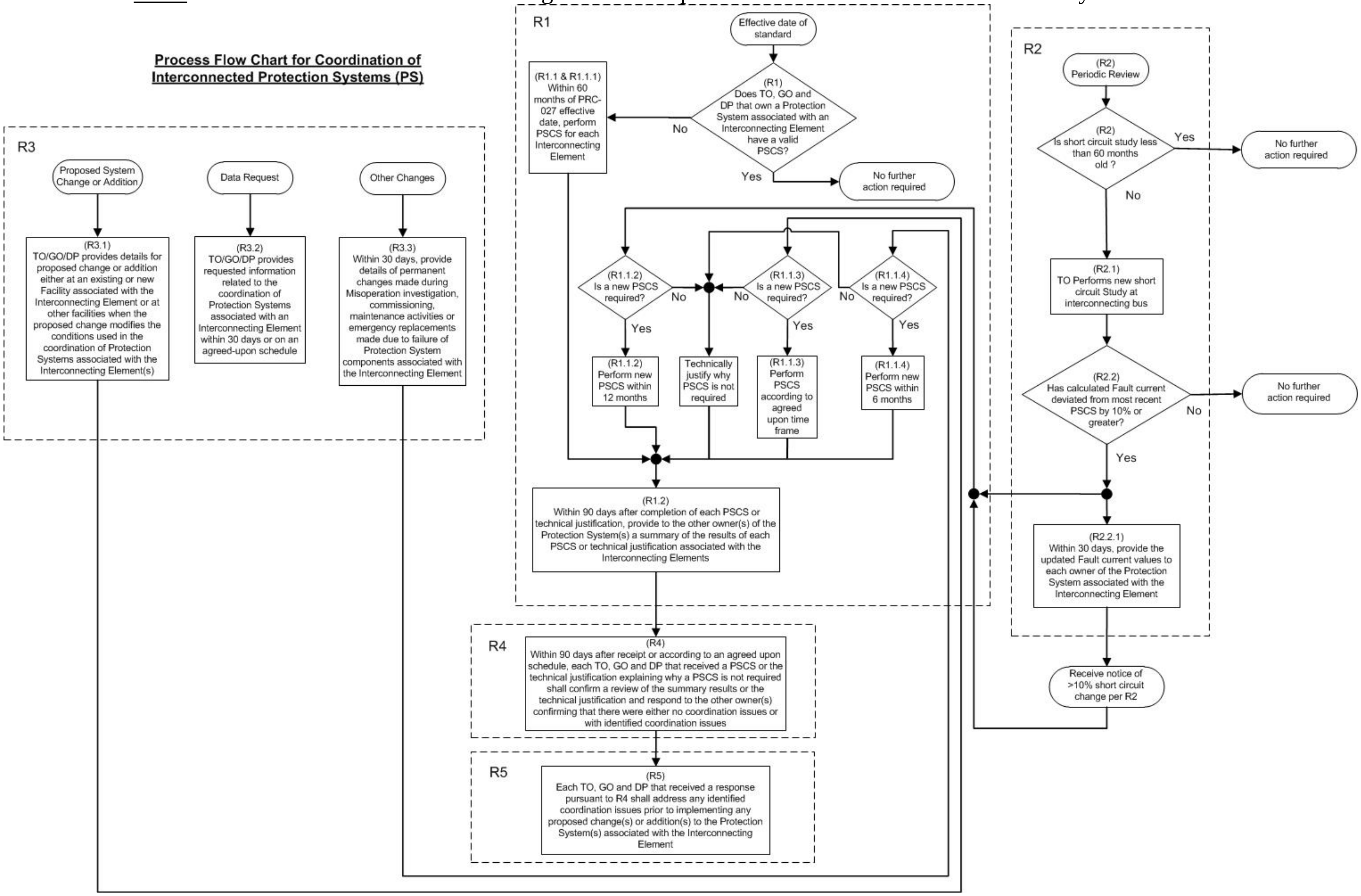
Requirement R4:

Requirement R4directs applicable entities, within 90 calendar days after receipt, to review the summary results of a PSCS or the technical justification, as described in Requirement R1, Part 1.2; and respond that they have reviewed and identified any issues. The drafting team contends 90 calendar days after receipt provides a reasonable time for the owners of Facilities to review.

Requirement R5:

The reliability objective of this requirement is to bring the process of Protection System coordination full circle by ensuring owners of Protection System(s) associated with Interconnecting Elements have communicated and addressed any identified coordination issues prior to implementing changes in the Protection System(s) (in-service date).

Process Flow Chart: Below is a complete representation of the process, including the relationships between requirements:
Note: All timeframes referenced in the diagram below represent "calendar month" or "calendar day" timeframes.



Example Process

An example of the interaction between entities required to gather the information to perform an accurate study is provided below. This example is given as general guidance only and is not intended to represent all situations that may occur. More detailed examples are provided along with Figures 1-5 in the section that follows this example.

- The initiating entity (Entity A) will contact the interconnecting entity (Entity B) and provide details of the change(s) and may also request up-to-date Protection System information.
- Entities A and B will determine whether a new PSCS is required. In this example both agree that a new study is required. The study may be a joint study, individual studies, or a single study provided by Entity A and reviewed and approved by Entity B. In this example, the latter will occur.
- Upon receipt of the above request for information, Entity B will provide the information within 30 calendar days, or an agreed upon time frame.
- Entity A will perform a PSCS using the information received.
- Entity A will provide a summary of the results of the study to Entity B within 90 calendar days of completing the PSCS.
- Entity B will review the summary information and, within 90 calendar days of receiving the study results from Entity A, respond as to whether any coordination issues were identified, and if any further action is required.
    - In cases where the study reveals that changes to Protection Systems are needed, Entity B would propose to Entity A revisions that achieve acceptable results.
    - Ultimately, both entities will collaborate in developing a mutually acceptable solution.

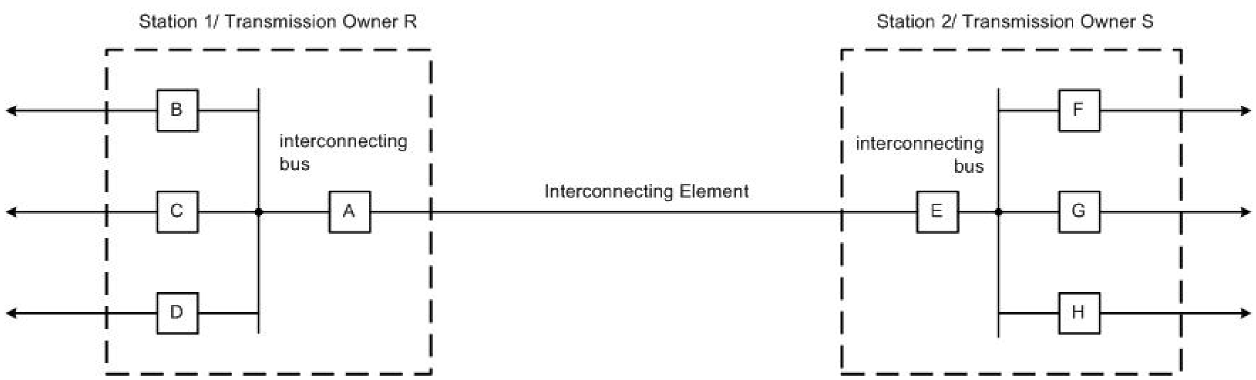
Diagrams

Introduction: The diagrams below are intended to provide guidance, to the owners of Facilities associated with the affected Interconnecting Element, for meeting the requirements of this standard. These examples are not intended to be inclusive of all situations and are based on the assumption that entities employ the appropriate engineering expertise and due diligence in developing settings for their Protection Systems. The examples given also assume a single owner as the initiator of a Protection System Coordination Study (PSCS) for the applicable Interconnecting Element. In actuality, any owner or owners may initiate the process. After the reviews of the PSCS or a summary of results, and prior to implementation of changes, the owners must work together to resolve any coordination issues identified during those reviews.

NOTES:

1. Protection System Coordination Studies are typically performed assuming maximum generation and all Facilities in service.
2. Protection Systems of the Transmission Owners, Generator Owners, and Distribution Providers described in the Figures and examples below do not include any systems or components enumerated in the 'Background Section' of this standard under "Other Aspects of Coordination of Protection Systems Addressed by Other Projects".
3. In the Figures below, the locations of the interconnecting bus(s) referenced in Requirement 2 are indicated.

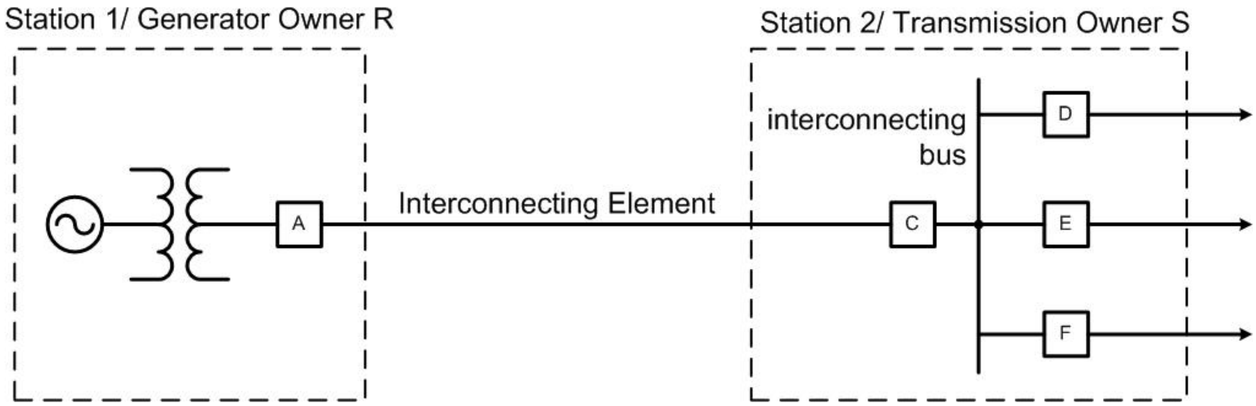
Figure 1



In Figure 1 above, the Interconnecting Element between the Transmission Owners is the transmission line between Breakers A and E.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 1, Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers E, F, G, and H. Likewise, Owner S is to develop Protection System settings associated with Breaker E. Owner R is to review the Protection System settings associated with Breaker E (provided by Owner S) for coordination issues with the Protection System settings associated with Breakers A, B, C, and D.

Figure 2

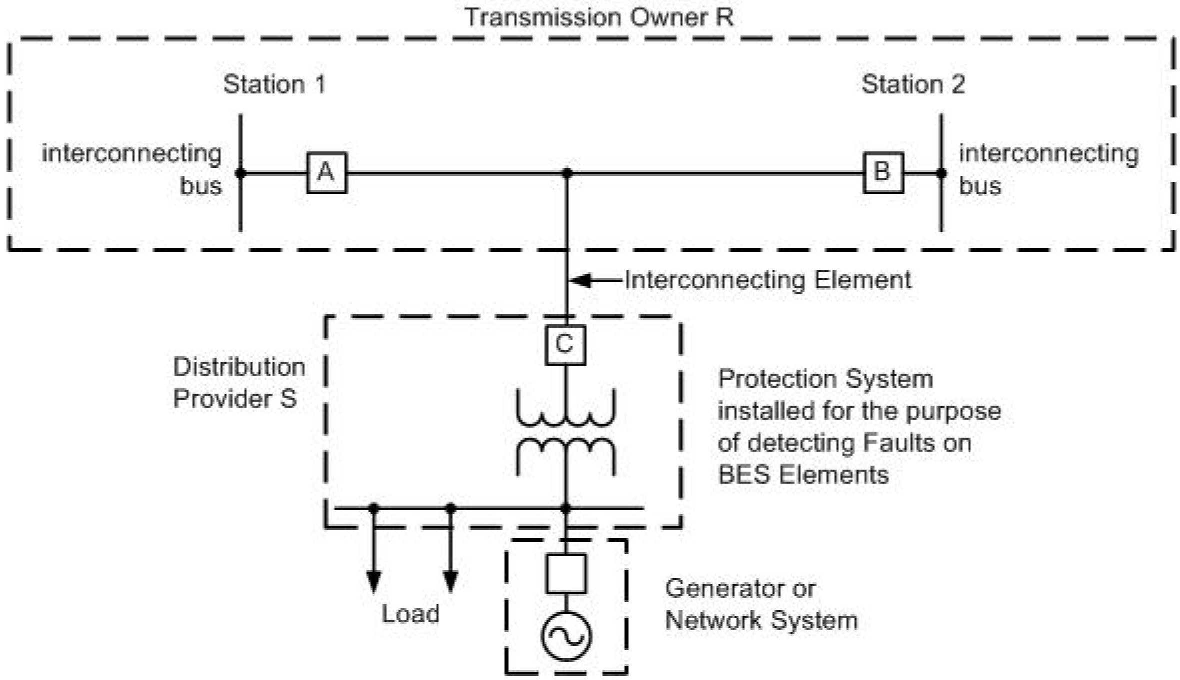


In Figure 2 above, the Interconnecting Element between the Transmission Owner and the Generator Owner is the transmission line or bus between Breakers A and C.

Note: Depending on the actual configuration and/or ownership, Breaker A may, or may not, exist as a GSU unit high-side breaker or a line breaker.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 2, Owner R is to develop Protection System settings associated with Breaker A. Transmission Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, Owner S is to develop Protection System settings associated with Breaker C. Generator Owner R is to review the Protection System settings associated with Breaker C (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

Figure 3



In Figure 3 above, the Interconnecting Element between the Transmission Owner and the Distribution Provider is the transmission line (or tap) between the Distribution Provider's Breaker C and the point of connection to the line between the Transmission Owner's Breakers A and B. Therefore, the applicable Protection Systems per this standard are those at Breakers A, B and C.

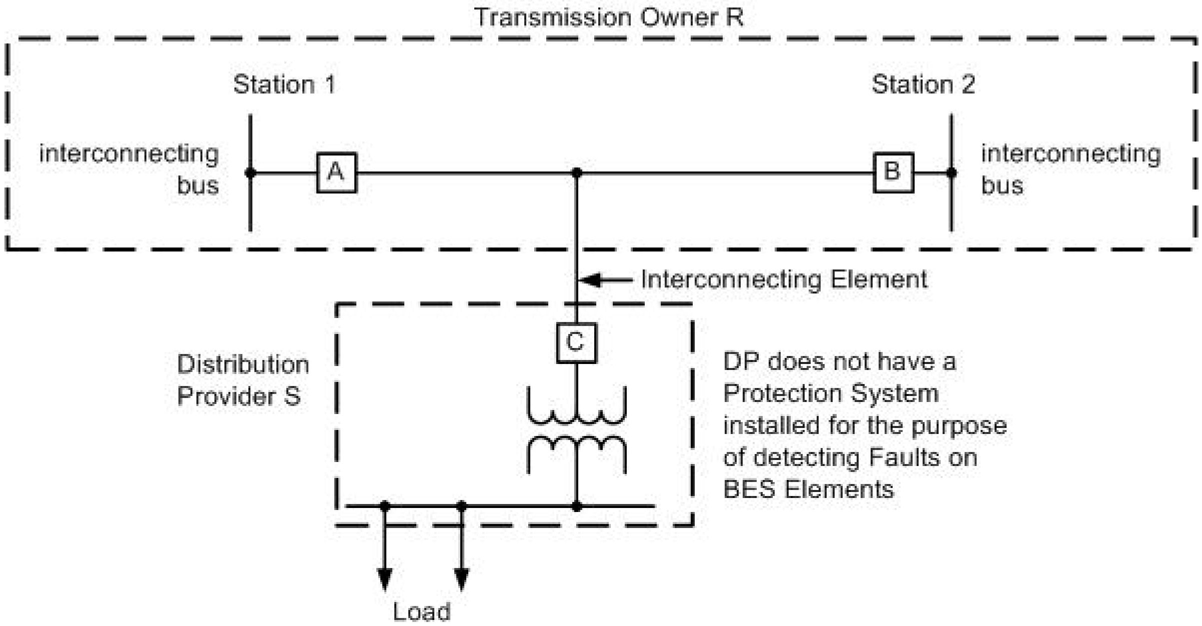
Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 3, Distribution Provider S is to develop Protection System settings associated with Breaker C. Transmission Owner R is to review the Protection System settings associated with Line Breaker C (provided by Distribution Provider S) for coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2.

Notes:

A PSCS is required per this standard for this example if a Protection System at the Distribution Provider's substation is installed for the purpose of detecting Faults on BES Elements.

Protection Systems installed for the purpose of detecting Faults on BES Elements do not include relays that, though they may operate for such Faults, are not installed specifically for that purpose. As an example, reverse power relays are often installed to detect situations where the transmission source for a power transformer becomes de-energized (for whatever reason) while the distribution bank remains energized from a source on the low-voltage side. In this case, the settings of the reverse power relay are typically calculated based on the charging current of the transformer from the low-voltage side. Although relays installed and set in this manner may operate as a result of a Fault on a BES Element, they are not specifically installed for the purpose of detecting that Fault.

Figure 4



The configuration above is an example excluded from this standard because the Distribution Provider S does not own Protection Systems installed for the purpose of detecting Faults on BES Elements.

Figure 5

Transmission/Generation Facility with Multiple Owners

Note: In a large majority of cases, Figure 2 would be applicable for most generator interconnections. In Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T.

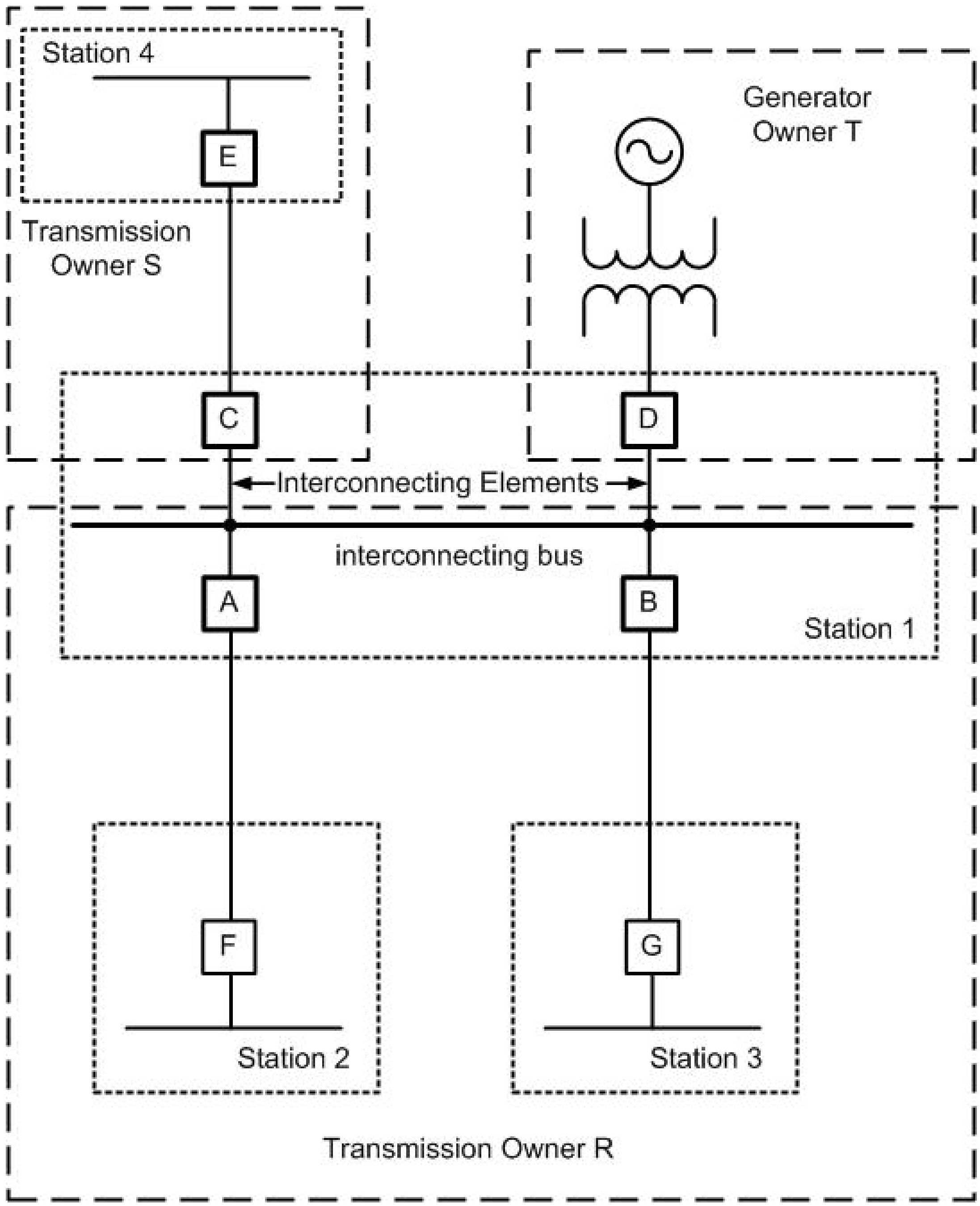


Figure 5 above illustrates the Interconnecting Elements between the Transmission Owners R and S and Generator Owner T. In this example, Transmission Owner S and Generator Owner T are not directly interconnecting to each other at Station 1. All direct interconnections are between Owner R and each of the other Owners connected to the common bus at Station 1.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 5:

Owner S is to develop Protection System settings associated with Breakers C and E.

Owner T is to develop Protection System settings associated with Breaker D, the generator, and its associated equipment.

Owner R is to develop Protection System settings associated with Breakers A, B, F and G.

Owner R is to review the Protection System settings associated with Breaker C, E, D, and the generator Protection System (provided by Owners S and/or T) for coordination issues with the Protection System settings associated with Breakers A and B.

Owner S is to review the Protection System settings associated with Breakers A, F, B, G, D, and the generator Protection System (provided by Owners R and/or T) for coordination issues with the Protection System settings associated with Breaker C. To perform this review, it will be necessary that Transmission Owner R provide Owner S with its settings for Breakers A, F, B, and G, as well as the settings for Breaker D and generator Protection System settings provided to Owner R by Generator Owner T.

Owner T is to review the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R and/or S) for coordination issues with the Protection System settings associated with Breaker D or the generator Protection System. In order to perform this review, it will be necessary that Transmission Owner R provide Generator Owner T with its settings for Breakers A, F, G, and B, as well as the settings for Breaker C and E provided to Owner R by Transmission Owner S.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Draft 1 of SAR posted for comment June 11, 2007 – July 10, 2007.
2. SAR approved on August 13, 2007.
3. First posting of revised standard PRC-001-2 on September 11, 2009.
4. Transitioned from a revision of PRC-001-1 to development of PRC-027-1 based on industry comments, Quality Review feedback, and consideration of FERC directives relative to the existing requirements of PRC-001-1.
5. Draft 1 of PRC-027-1 was posted for a 45-day formal comment and initial ballot from May 21 – July 5, 2012.
6. Draft 2 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from November 16 – December 17, 2012.
7. Draft 3 of PRC-027-1 was posted for a 30-day formal comment and successive ballot from June 4 – July 3, 2013.
8. Draft 4 of PRC-027-1 was posted for a 45-day formal comment and ballot from September 18 – November 1, 2013. Note: Posting and ballot postponed as of September 27, 2013.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: “To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.” This standard incorporates and clarifies the coordination aspects of Requirements R2 and R3 from PRC-001-2. The SPCSDT is soliciting stakeholder feedback on draft 4 of PRC-027-1 during a 45-day formal comment period with parallel ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Ballot	November - December 2013
Final Ballot	March 2014
BOT Adoption	May 2014

Effective Dates:

PRC-027-1 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~PRC-027-1 shall become effective on the first day of the first calendar quarter that is 12 months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. For Interconnected Elements between Canadian Facilities (that recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date.~~

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2007-06 – PRC-027-1	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here.

The following terms are defined for use only within PRC-027-1~~, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms~~:

~~Interconnected~~Interconnecting Element
~~:~~ A Bulk Electric System (BES) Element that electrically joins ~~facilities~~ Facilities:
a) owned by~~:~~
~~a)~~ separate Registered Entities, or
b) owned by the same Registered Entity that represents multiple functional entity responsibilities (~~Distribution Provider~~Transmission Owner, Generator Owner, or ~~Transmission Owner~~Distribution Provider)~~.~~

Protection System Coordination Study~~:~~
A study ~~that demonstrates~~documenting that existing or proposed Protection Systems operate in the ~~desired~~intended sequence for clearing Faults.

Other Aspects of Coordination of Protection Systems Addressed by Other Projects:

Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects:

- Underfrequency Load shedding programs are addressed in PRC-006-1. Generator performance during frequency excursions is being addressed in PRC-024-1 by Project 2007-09 Generator Verification.
- Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed in PRC-024-1 by Project 2007-09, Generator Verification.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is ~~being~~ addressed in PRC-019-1 by Project 2007-09~~, Generator Verification~~.
- Transmission relay loadability is addressed in PRC-023-2.
- Generator relay loadability ~~will be~~is addressed in PRC-025-1 by Project 2010-13.2, Phase 2 of Relay Loadability: Generation~~, in Project 2010-13.2~~.
- Protective relay response during power swings will be addressed by ~~Phase 3 of~~ Project 2010-13.3, Phase 3 of Relay Loadability: Stable Power Swings.
- Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and are addressed ~~will be improved~~ in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

The SPCSDT ~~believes~~contends that including these other aspects of protection coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Coordination for Performance During Faults**

2. **Number:** PRC-027-1

3. **Purpose:** To coordinate Protection Systems for ~~Interconnected~~Interconnecting Elements, such that Protection System components operate in the ~~desired~~intended sequence during Faults.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider (that own Protection Systems identified in the Facilities section 4.2 below)

   4.2 Facilities: ~~For the purpose of the requirements contained herein, the following~~

   Protection Systems ~~owned by each Functional Entity in 4.1 above are those to which these requirements are applicable.~~:

   a) ~~**4.2.1** Protection Systems~~ installed for the purpose of detecting Faults on ~~Interconnected~~Interconnecting Elements ~~of the BES~~, and

   ~~a)~~b) that require coordination for isolating those faulted Elements

5. **Background:**

On December 7, 2006, the NERC Planning Committee approved the assessment of Reliability Standard PRC-001 – System Protection Coordination, prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF noted problems with the applicability to entities and vagueness of requirements in the existing PRC-001-1 reliability standard. The SPCTF concluded that the deficiencies of Reliability Standard PRC-001-1 were magnified by having requirements that addressed coordination of protection functions and capabilities in the operating and planning timeframes. Consequently, the SPCTF recommended that the requirements for the operating horizon and planning horizon be clearly delineated, and possibly divided into two standards.

The NERC Standards Committee approved a Standard Authorization Request that included the modifications noted by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

The Project 2007-06 – System Protection Coordination Standard Drafting Team (SPC~~-~~SDT) posted an initial draft of Reliability Standard PRC-001-2 on September 11, 2009 for comments. In that draft, the SPC~~-~~SDT attempted to address all issues identified by the SPCTF assessment of PRC-001-1. The SPC~~-~~SDT responded to the comments from the initial posting of PRC-001-2, and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC Quality Review (QR) in December 2010. Based on the results from the QR, and after informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to follow the SPCTF recommendation and focused their knowledge and expertise on developing a new results-based standard, concentrating on the reliability aspects (the coordination of new and existing protective systems in the planning horizon) associated with Requirements R3 and R4 of PRC-001-1. These aspects of coordination are incorporated and clarified in the proposed Reliability Standard PRC-027-1 – Protection System Coordination for Performance During Faults with the stated purpose:

> *"To coordinate Protection Systems for ~~Interconnected~~Interconnecting Elements, such that Protection System components operate in the ~~desired~~intended sequence during Faults."*

~~Additionally, the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address "the appropriate use of time delays in relays," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination.~~

PRC-001-1 contained a non-specific training requirement (Requirement R1), three operating time frame requirements (Requirements R2, R5 and R6), and two planning requirements (Requirements R3 and R4). The SPC-SDT transferred the responsibility of addressing the operating Requirements R2, R5, and R6 to the drafting team for Project 2007-03 Real-time Operations, charged with revising the TOP group of reliability standards. The Project 2007-03 drafting team retired Requirements R2, R5, and R6 of PRC-001-1 because they addressed data and data requirements that are now included in Reliability Standard TOP-003-2. The NERC Board of Trustees adopted Reliability Standards TOP-003-2 and PRC-001-2 on May 9, 2012.

Proposed Reliability Standard PRC-027-1 incorporates the aspects of coordination found in Requirements R2 and R3 of PRC-001-2. ~~The SPC SDT revised PRC-001-2. Revisions include the removal of Requirements R2 and R3 (formerly Requirements R3 and R4 of PRC-001-1). These two legacy requirements are being retired because the aspects of coordination they address are incorporated in the proposed Reliability Standard PRC-027-1, Protection System Coordination for Performance During Faults. The SPCSDT believes the training aspects of Requirement R1 would be more appropriately addressed by the PER group of Reliability Standards. Consequently, the drafting team has recommended via the NERC Issues Database that the future drafting team charged with revising PER-005-1 incorporate the reliability objective of Requirement R1 into the revised standard. Until that occurs, Requirement R1 of PRC-001-2 must remain in the standard. In an effort to improve PRC-001-2 until it can be fully retired, the drafting team has provided a measure to accompany Requirement R1. The Applicability section was also updated to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)~~

With the reliability intent of these two legacy requirements being addressed in PRC-027-1, it is necessary to retire them from PRC-001-2.

Requirements and ~~Other Aspects of Coordination of Protection Systems Addressed by Other Projects:~~

~~Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects.~~

- ~~Underfrequency Load shedding programs are addressed in PRC-006-1. Generator performance during frequency excursions is being addressed in PRC-024-1 by Project 2007-09 Generator Verification.~~
- ~~Undervoltage Load shedding programs are addressed by PRC-010-0 and PRC-022-1, and will be improved by Project 2008-02, Undervoltage Load Shedding. Generator performance during voltage excursions is addressed in PRC-024-1 by Project 2007-09, Generator Verification.~~
- ~~Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is being addressed in PRC-019-1 by Project 2007-09.~~
- ~~Transmission relay loadability is addressed in PRC-023-2.~~
- ~~Generator relay loadability will be addressed in PRC-025-1 by Phase 2 of Relay Loadability: Generation, in Project 2010-13.2.~~
- ~~Protective relay response during power swings will be addressed by Phase 3 of Project 2010-13.3, Relay Loadability.~~
- ~~Misoperations identified as coordination issues are investigated and have Corrective Action Plans created in accordance with PRC-003-0 and PRC-004-2a, and will be improved in PRC-004-3 by Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).~~

~~The SPC SDT believes that including these other aspects of protection coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.~~

B. ~~Requirements and~~ Measures

Rationale for R1:

Part 1.1 A Protection System Coordination Study (PSCS) is necessary to verify coordination of Protection Systems for existing and new ~~Interconnected~~Interconnecting Elements. The drafting team defines the term "~~Interconnected~~Interconnecting Element" as "A BES Element that electrically joins ~~facilities~~ Facilities: a) owned by~~:~~ ~~a)~~ separate Registered Entities, or b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner)."

Part 1.1.1 The drafting team ~~believes~~contends 60 calendar months is an appropriate period of time for entities to perform the PSCS required where no study exists. The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with ~~Interconnected~~Interconnecting Elements that warrants a shorter time frame.

Part 1.1.2 The drafting team ~~believes~~contends that 12 calendar months is an appropriate period of time for entities to perform the studies required when determining, or being notified of, a 10% or greater Fault current change at an interconnecting bus, where such conditions may warrant a new PSCS, or to technically justify why no such study is required~~, e.g., when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current~~. Refer to the Application Guidelines for Requirement R1 for examples of Protection Systems where technical justifications may be used.

Part 1.1.3 The drafting team ~~believes~~contends that entities must perform the studies required when proposing or being notified of changes identified in Requirement R3, Part 3.1, or to technically justify why no such study is needed. The drafting team ~~believes~~contends the timeframe associated with the requirement for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies ~~associated with Requirement R3, Part 3.1~~ is unnecessary because notification of such a change may occur weeks or years prior to the change. The initiating entity has the incentive to provide the identified information as soon as possible to ensure timely implementations.

Part 1.1.4 The drafting team contends that entities must perform the studies required when notified of changes identified in Requirement R3, Part 3.3, or to technically justify why no such study is needed. The drafting team ~~believes~~contends that six months is an appropriate period of time for entities to perform the studies required or to technically justify why no such study is needed when details of changes are provided associated with Requirement R3 Part 3.3.

Part 1.2 The drafting team ~~believes~~contends to properly ensure coordination of Protection Systems associated with ~~Interconnected~~Interconnecting Element(s), all entities need to share the summary of results of a PSCS and assess the study results. The drafting team ~~believes~~contends that 90 calendar days is a reasonable time for the entity to provide the results of the PSCS performed in accordance with Requirement R1, Part 1.1 to the other owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element(s).

Note: In cases where a single group performs an overall coordination study for a given ~~Interconnected~~Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS ~~would be~~is sufficient for use by ~~both Registered Entities~~all entities.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

1.1. Perform a Protection System Coordination Study (PSCS) for each of its ~~Interconnected~~Interconnecting Elements as follows:

1.1.1 Within 60 calendar months after the effective date of this standard, if no PSCS for that ~~Interconnected~~Interconnecting Element exists.

1.1.2 Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required.

1.1.3 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or ~~within~~technically justify why such a study is not required.

~~1.1.3~~**1.1.4** Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3~~;~~, or technically justify why such a study is not required.

1.2. Within 90 calendar days after the completion of each PSCS~~,~~ or the technical justification pursuant to Requirement R1, Part 1.1, provide to the other owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element(s~~),~~): a summary of the results of each PSCS performed~~ pursuant to Requirement R1, Part 1.1, (~~, including, at a minimum, the Protection Systems reviewed, the associated Fault ~~currents~~current(s) used, any issues identified, and any revisions or actions proposed~~).~~; or the technical justification.

M1. Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1,~~ and~~ 1.1.2, 1.1.3, and 1.1.~~3~~4 is a dated PSCS, or the summary of the results of each PSCS (hard copy or electronic file formats) demonstrating the time frames specified or agreed to in Parts 1.1.1, 1.1.2, 1.1.3, and 1.1.~~3~~4 were achieved. Acceptable evidence of a technical justification for not performing a PSCS as specified in Parts 1.1.2, 1.1.3, and 1.1.~~3~~4 may include, but is not limited to, documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any ~~aspects~~aspect of coordination.

M2. Acceptable evidence for Requirement R1, Part 1.2 is dated documentation demonstrating that the summary of the results of each PSCS or the technical justification (hard copy or electronic file formats) were provided within the specified time frame to the owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element(s).

Rationale for R2: This requires a periodic review of Fault currents at the interconnecting bus and providing the results to the applicable entities when changes occur that meet the criteria of Requirement R2. It is important that ~~interconnected~~interconnecting Facility owners are kept aware of changes that could affect proper performance of their Protection Systems. The Transmission Owner is identified as the entity responsible for performing the short circuit studies because they maintain the data necessary to perform the studies. Note: short circuit studies are used to determine the Fault current values at the interconnecting bus where a PSCS exists. These studies are typically performed assuming maximum generation and all Facilities in service.

The drafting team ~~believes~~contends 60 calendar months provides the entities flexibility to ~~either technically justify why Fault current does not affect the Protection System coordination, or~~ schedule and perform the activities specified in Requirement R2, Parts 2.1 and 2.2.

~~The drafting team recognizes the coordination of some types of Protection Systems is unaffected by changes in Fault current and, where technically justified, can be exempted from the short circuit review.~~

Part 2.1 The drafting team ~~believes~~contends maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus are necessary quantities needed to review the coordination.

Part 2.2 The drafting team is including this equation to assure a consistent approach is used by each Transmission Owner when calculating the percent change in Fault current values.

Part 2.2.1 The drafting team ~~believes~~contends the 30-calendar day time frame is reasonable for providing the Fault current information to the owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element. The drafting team determined that a change in Fault current of 10% indicates an appropriate point at which to provide this information, based on the fact that Protection Systems are typically set with margins above 10%.

R2. For each ~~Interconnected~~Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months~~, technically justify why Fault current does not affect the Protection System coordination, or~~: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

2.1. Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at ~~the~~its interconnecting bus(s) where a ~~Protection System Coordination Study (~~PSCS~~)~~ is available ~~per~~ pursuant to Requirement R1.

2.2. Calculate the percent change between the Fault current values (single line to ground and 3-phase for ~~the~~its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation:

$$\%\ Change = \left|\frac{Iscs - Ipscs}{Ipscs}\right| x\ 100$$

Where: I_{scs} = Fault current value from present short circuit study

And: I_{pscs} = Fault current value used in the most recent PSCS

2.2.1 Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (I_{scs}) to each owner of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element~~.~~(s).

~~**M3.** Acceptable evidence of technical justification for not performing a short circuit study as specified in Requirement R2, could be documented engineering analyses or assessments that demonstrate why Fault current does not impact any aspects of coordination.~~

~~M4.~~**M3.** Acceptable evidence for Requirement R2, Parts 2.1 and 2.2 is dated documentation (hard copy or electronic file formats) that contains the present Fault current values from the short circuit study for each interconnecting bus analyzed, and identifies the percent change from the Fault current values used in the most recent PSCS determined by the equation.

~~M5.~~**M4.** Acceptable evidence for Requirement R2, Part 2.2.1 is dated documentation (hard copy or electronic file formats) that the updated Fault current values (I_{scs}), were provided within the specified timeframe to each owner of the Protection System associated with the ~~Interconnected~~Interconnecting Element.

Rationale for R3: This requires the transfer of appropriate information to the entities associated with each ~~Interconnected~~Interconnecting Element due to circumstances identified in Parts 3.1, 3.2, and 3.3.

Part 3.1 The reliability objective of this requirement is to enable the process of conducting PSCSs by ensuring that the information is provided to the owner(s) of the Protection Systems associated with ~~Interconnected~~Interconnecting Element(s). The drafting team ~~believes~~contends that information about any proposed change or addition (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the ~~Interconnected~~Interconnecting Element. The drafting team ~~believes~~contends that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The list provided in the requirement is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. Examples of changes to generator units that result in impedance changes could include replacements and re-ratings. This requirement also pertains to changes identified as a result of studies performed in Requirement 1, Part 1.1.

Part 3.2 The purpose of this requirement is to provide a means for an entity to receive the requested information in a timely manner in order to perform a PSCS, as required in Requirement 1, Parts 1.1.1, 1.1.2, 1.1.3, and 1.1.~~3~~4. The drafting team ~~believes~~contends 30 calendar days after receipt of the request is a sufficient amount of time to provide this information. The requirement also provides some flexibility for the parties involved to determine an otherwise agreed-to schedule, if appropriate.

Part 3.3 The drafting team ~~believes~~contends 30 calendar days is sufficient time to provide the information.

Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that describes the information listed in Requirement R3, Parts 3.1 and 3.3 below is sufficient for use by all entities.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same ~~Interconnected~~Interconnecting Element: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the ~~Interconnected~~Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the ~~Interconnected~~Interconnecting Element(s).

- New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios
- Changes to a transmission system Element that alter any sequence or mutual coupling impedance
- Changes to generator unit(s) that result in a change in impedance

- Changes to the generator step-up transformer(s) that result in a change in impedance

3.2. Requested information related to the coordination of Protection Systems associated with an ~~Interconnected~~Interconnecting Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule.

3.3. Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.

~~M6.~~**M5.** Acceptable evidence for Requirement R3, Part 3.1 may include, but is not limited to, documentation (hard copy or electronic file formats) demonstrating that a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) as identified in the bulleted list, was provided to each responsible entity connected to the same ~~Interconnected~~Interconnecting Element.

~~M7.~~**M6.** Acceptable evidence for Requirement R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was provided according to the agreed-upon schedule, or within 30 calendar days absent such an agreement.

~~M8.~~**M7.** Acceptable evidence for Requirement R3, Part 3.3 is dated documentation (hard copy or electronic file formats) demonstrating the information pertinent to the permanent changes made was provided within 30 calendar days.

Rationale for R4: This requirement ensures owner(s) of Protection System(s) associated with ~~Interconnected~~ Interconnecting Elements ~~affirm~~confirm that the Protection System(s) applied ~~are acceptable per~~were reviewed and a response was provided to the ~~conditions identified in Parts 4.1 and 4.2~~other owner(s). The review assures that the owners of Protection Systems associated with the affected Interconnecting Element are aware of the changes and have responded with comments if necessary.

~~Part 4.1~~ The drafting team ~~believes~~contends 90 calendar days is a reasonable time for the owner(s) of Protection System(s) associated with ~~Interconnected~~Interconnecting Elements to review the summary results of a PSCS or the technical justification and respond. Note: ~~Per~~Pursuant to Requirement R1, Part 1.2, at a minimum, the summary of the results of a PSCS must include the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed. The response should indicate ~~acceptance with~~ the ~~review~~ results~~/conclusions; or rejection~~ of ~~or disagreement with~~ the ~~review results/conclusions~~PSCS or the technical justification were reviewed and ~~offer of suggestions/modifications to resolve~~, if applicable, any identified ~~coordination~~ issues.

Note: The drafting team recognizes there could be situations where one owner may not agree with the other owner's protection philosophy but they ~~accept the proposed changes since~~ can confirm that there were no identified coordination issues ~~were identified~~.

~~Part 4.2 The drafting team believes that proposed changes or modifications (including project schedules) to Facilities associated with the Interconnected Element, as described in Requirement R3, Part 3.1, or modifications suggested in Requirement R4, Part 4.1 must be communicated and accepted prior to the in-service date. Acceptance assures that the coordination of Protection Systems associated with the affected Interconnected Element is achieved.~~Note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that describes the information listed in Requirement R3, Parts 3.1 and 3.3 is sufficient for use by all entities.

~~**R4.**~~ Each Transmission Owner, Generator Owner, and Distribution Provider that received a summary of the results of a PSCS or a technical justification explaining why a PSCS is not required (pursuant to Requirement R1, Part 1.2) shall~~: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]~~

~~R5.~~**R4.** ~~Within~~, within 90 calendar days after receipt~~,~~ or according to an agreed upon schedule, review the summary of the results ~~of a PSCS (per Requirement R1, Part 1.2)~~or the technical justification, and respond to the other owner(s~~):~~) either: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- ~~Accepting~~Confirming that the ~~results, or~~
- ~~Rejecting~~summary of the results was reviewed and ~~suggesting modifications to resolve any identified~~no ~~coordinati~~coordination issues were identified, ~~on issues.~~
- ~~Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1~~ or ~~Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.~~
- Confirming that the summary of the results was reviewed and any identified coordination issue(s) were noted, or
- Confirming that a technical justification was reviewed and no issue(s) were identified, or
- Confirming that a technical justification was reviewed and any identified issue(s) were noted

~~M9.~~**M8.** Acceptable evidence for Requirement R4~~, Part 4.1~~ is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement.

Rationale for R5: This requirement obligates owner(s) of Protection System(s) associated with Interconnecting Elements to communicate and address any identified coordination issues prior to implementing the proposed Protection System(s) change(s) or addition(s); i.e., the in-service date of the Protection System(s).

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that received a response pursuant to Requirement R4 shall address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

~~M10.~~**M9.** Acceptable evidence for Requirement ~~R4, Part 4.2~~R5 is dated documentation (hardcopy or electronic file formats) demonstrating that~~,~~ a response pursuant to Requirement R4 was received and that any identified coordination issues were addressed prior to implementation of any proposed Protection System(s) changes or ~~modifications, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted~~additions.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System associated with an ~~Interconnected~~Interconnecting Element shall each keep data or evidence to show compliance with Requirements R1, R2, R3, R4, and ~~R4~~R5, and Measures M1 through ~~M10~~M9, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner or Distribution Provider that owns a Protection System at a Facility associated with an ~~Interconnected~~Interconnecting Element is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. ~~OR~~ OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than	The responsible entity performed a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4, or technically justified why a study was not required but was late by more than 60 calendar days. ~~OR~~ ~~The responsible entity provided the Protection System~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			with Requirement R1, Part 1.2, but was late by less than or equal to 10 calendar days.	10 calendar days but less than or equal to 20 calendar days.	20 calendar days but less than or equal to 30 calendar days.	~~Coordination Study~~ OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar days. OR The responsible entity failed to perform a Protection System Coordination Study on an ~~Interconnected~~Interconnecting Element in accordance with Requirement R1, Parts 1.1.1, 1.1.2, 1.1.3, or 1.1.~~3~~4. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2, 1.1.3, or 1.1.~~3~~4. OR The responsible entity failed to provide a summary of the results of each Protection System Coordination Study

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~results~~ or a technical justification in accordance with Requirement R1, Part 1.2.
R2	Operations Planning, Long-term Planning	Medium	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by less than or equal to 30 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study, as required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days.	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 30 calendar days but less than or equal to 60 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 60 calendar days but less than or equal to 90 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 90 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 90 calendar days. OR The Transmission Owner failed to perform a short circuit study, as required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent change between the Fault

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	currents, according to the equation designated in Requirement R2, Part 2.2. OR The Transmission Owner provided the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, the updated Fault current values, as required in Requirement R2, Part 2.2.1.
R3	Operations Planning, Long-term Planning	Medium	The responsible entity	The responsible entity	The responsible entity	The responsible entity failed to provide the owner(s) of the Facility associated with the ~~Interconnected~~Interconnecting Element, details for any proposed change or addition identified in Requirement R3, Part 3.1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			provided the requested information required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days.	provided the requested information required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	provided the requested information required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	OR The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the information required in Requirement R3, Part 3.3.
R4	Operations Planning, Long-term Planning~~Operations Planning~~	Medium	The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following ~~the~~ receipt of the Protection System Coordination Study summary of the results ~~of the Protection System Coordination Study~~or technical justification, as required in Requirement R4~~,~~	The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1.~~	The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1.~~	The responsible entity responded in more than 120 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1~~.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~Part 4.1.~~ .	.	.	OR The responsible entity failed to review the ~~summary results of the~~ Protection System Coordination Study summary of the results -or the technical justification provided to them in accordance with Requirement R4~~, Part 4.1~~. OR The responsible entity failed to respond to the other owners(s) in accordance with Requirement R4~~, Part 4.1.~~ ~~OR~~ ~~The responsible entity failed to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element accepted the Protection System(s) changes including the resolution of any identified coordination issues, prior to implementation of those changes, as required in Requirement R4, Part 4.2~~.
R5	Operations Planning, Long-term Planning	Medium				The responsible entity failed to address any identified coordination issue(s), prior to implementing any proposed change(s) or addition(s) to the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Protection System(s) associated with the Interconnecting Element(s) in accordance with Requirement R5.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Application Guidelines

Guidelines and Technical Basis

Purpose:

To coordinate Protection Systems for ~~Interconnected~~Interconnecting Elements, such that Protection System components operate in the ~~desired~~intended sequence during Faults.

This standard requires that separate Registered Entities communicate with each other to coordinate Protection System components on existing ~~Interconnected~~Interconnecting Elements; and communicate with each other prior to the energization of new or modified Protection Systems associated with ~~Interconnected~~Interconnecting Elements. The goal of the coordination is to verify that the Protection Systems intended for sensing Faults will operate in the ~~desired~~intended sequence for internal and external Faults on the ~~Interconnected~~Interconnecting Element.

Requirement R1:

This requirement directs the applicable entities to perform a Protection System Coordination Study (PSCS) for every ~~Interconnected~~Interconnecting Element to verify coordination of existing Protection Systems where no recent study exists; or when Facility configuration changes are made, or where Fault current changes of 10% or more have occurred. In developing the language to define a PSCS, the System Protection Coordination Standard Drafting Team (SPC-SDT) considered various reference books discussing protective relaying theory and application, along with the following description of "coordination of protection" from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Using the reference material cited above as guidance, the drafting team defined the term Protection System Coordination Study (PSCS) for use within the PRC-027-1 Reliability Standard as:

> "A study ~~that demonstrates~~documenting that existing or proposed Protection Systems operate in the ~~desired~~intended sequence for clearing Faults."

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PSCSs comprise a variety of assessments and underlying database activities that cumulatively serve to provide verification that Protection Systems will function as designed. Typical database activities performed during these studies include assembling impedance data for Fault studies and modeling Protection Systems. System conditions used in PSCSs include maximum generation with the transmission system under normal operating conditions and under single contingency conditions. Ultimately, the particular studies performed depend on the protective relays installed, their application, and the Protection System philosophies of each Transmission Owner, Generator Owner, and Distribution Provider. These studies may include graphical coordination of protection characteristics on time-current or impedance graphs; relay scheme simulation studies using sequence of operations during pre-defined Faults; and

sensitivity studies to confirm effective reaches, sufficient operating parameters (energy or operating torque), and adequate directional polarizing quantities.

Part 1.1.1:

The drafting team ~~believes~~contends applicable entities should have a documented PSCS for each ~~Interconnected~~Interconnecting Element to validate the Protection Systems associated with those ~~Interconnected~~Interconnecting Elements perform in a manner consistent with the purpose of this Standard. Additionally, the drafting team ~~believes~~contends that 60 calendar months is an appropriate amount of time for entities to perform the initial studies expected under this requirement. This period considers the time some entities may require to create project scopes, acquire proposals, and secure contracts to hire external resources that may be needed to perform the studies. The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with ~~Interconnected~~Interconnecting Elements that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.

~~Parts 1.1.2 and 1.1.3 further direct that PSCSs must be completed under the following two circumstances:~~

Part 1.1.2:

After notification of an identified 10% or greater change in Fault current (single line to ground and 3-phase for the interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1), the notified entities must perform a new PSCS of the ~~Interconnected~~Interconnecting Element or document why a study is not required. The drafting team recognizes that, based on the Protection Systems installed (e.g., current differential), a 10% or greater change in Fault current may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team ~~believes~~contends the 12-calendar month time frame associated with this requirement represents a reasonable period to perform the studies that are required after identification by the 60-calendar month Fault current review.

Part 1.1.3:

After proposing or being notified of a change at a Facility associated with the ~~Interconnected~~Interconnecting Element, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the proposed or notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team ~~believes~~contends the timeframe associated with performing a PSCS for any proposed changes or additions is contingent upon the project's scope and schedule. Specifying a time frame for performing studies associated with Requirement R3, Part 3.1 is unnecessary because notification of such a change may occur weeks or years prior to the change due to the wide variety of conditions that may be associated with a particular change. The drafting team sees the entity initiating any change as having the incentive to move this along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement ~~R4,~~ R5.

Part 1.1.4~~.2.~~:

After being notified of a change at a Facility associated with the Interconnecting Element associated with Requirement R3, Part 3.3, entities must perform a new PSCS, or technically justify why such a study is not required. The drafting team recognizes that, based on the scope of the notified change and/or the Protection Systems installed (e.g., current differential), the change may not necessitate a new PSCS be performed; therefore this part of the requirement includes the statement, "…or technically justify why such a study is not required." The drafting team ~~believes~~contends that six calendar months is an appropriate period of time for entities to perform the studies required, or to technically justify why no such study is needed~~, when details of changes are provided associated with Requirement R3 Part 3.3~~.

Examples of Protection Systems where technical justifications may be used include:

1. Differential elements
2. Distance elements where infeed is not used in determining reach for the protection scheme.
3. Supervised overcurrent elements enabled by:
   - Loss of potential condition
   - Some communication assisted tripping
   - Switch-Onto-Fault (SOTF)
4. Reverse power, definite time &/or time overcurrent elements:
   - Designed to coordinate during maximum generation with the transmission system under normal operating conditions and under single contingency conditions regardless of Fault current.
   - Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.).

Requirement R1, Part 1.2 directs the entity performing the PSCS to provide a summary of the study results or a technical justification to the affected ~~Interconnected~~Interconnecting Element owner(s).~~-~~ The drafting team ~~believes~~contends that 90 calendar days is a reasonable time for the entity to provide the results of the

PSCS it performed to the other owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element(s). (Note: In cases where a single group performs an overall coordination study for a given ~~Interconnected~~Interconnecting Element; a single document that meets the requirements for a summary of the results of the PSCS would be sufficient for use by both Registered Entities.) ~~As guidance, the drafting team lists the~~The following inputs and results of a PSCS ~~that may~~must be included in the summary provided pursuant to this requirement:

1. A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Facility, and which were reviewed for coordination of protective relays as part of the study, including the contingencies used in the evaluation.
2. A listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Facility under study.
3. A listing of any issues associated with the relay settings of the other owner(s) at the Facility that were identified by the study.
4. Any proposed revisions to a Protection System or its protective relay settings that were identified by the study.

Requirement R2:

The drafting team investigated various inputs that would trigger a review of the existing PSCSs and determined, through the experience of the drafting team members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated PSCS may be necessary. ~~-~~These variations could result from the accumulation of incremental changes over time. This requirement mandates the Transmission Owner ~~either provide a technical justification stating why Fault current does not affect the Protection System coordination of a specific Interconnected Element or~~ perform a periodic review of Fault currents.

~~**Examples of Protection Systems where technical justifications may be used include:**~~

~~5. Differential elements~~

~~6. Distance elements where infeed is not used in determining reach for the protection scheme.~~

~~7. Supervised overcurrent elements enabled by:~~

- ~~Loss of potential condition~~
- ~~Some communication assisted tripping~~
- ~~Switch-Onto-Fault (SOTF)~~

~~8. Reverse power, definite time &/or time overcurrent elements:~~

- ~~Designed to coordinate during maximum generation with the transmission system under normal operating conditions and under single contingency conditions regardless of Fault current.~~

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- ~~Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.).~~

The short circuit study provides the Fault current values used to calculate the percent change between the most recent PSCS and the present Fault current values indicated by the short circuit study performed pursuant to Requirement R2, Part 2.1. ~~-~~This calculation is necessary to identify Fault current changes that must be communicated in accordance with Requirement R2, Part 2.2. Short circuit studies are typically performed assuming maximum generation and all Facilities in service.

The drafting team ~~believes~~contends that 60 calendar months is an appropriate interval for ~~technically justifying why Fault currents do not affect the Protection System coordination of a specific Interconnected Element, or for~~ reviewing Fault currents. The drafting team ~~believes~~contends studies associated with changes that would affect the coordination in less than 60 calendar months would be triggered by conditions addressed by other requirements in this standard.

Requirement R2, Part 2.2.1 further directs the Transmission Owner to, within 30 calendar days, inform each owner of the Facility associated with the ~~Interconnected~~Interconnecting Element when short circuit studies indicate that 10% changes in Fault current have occurred at the interconnecting bus(s). ~~-~~The drafting team ~~believes~~contends the 30-calendar day time frame associated with this requirement is reasonable for providing the Fault current information to the ~~interconnected~~interconnecting entity(s) and is consistent with other NERC reliability standards.

In Requirement R2, the Transmission Owner is identified as the functional entity responsible for performing the short circuit studies because they maintain the data required to perform the studies. ~~-~~Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.

Application Guidelines

Application Guidelines

Requirement R3:

This directs the registered functional entity initiating any proposed change or addition to provide the details to the other affected entities of the ~~Interconnected~~Interconnecting Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes. ~~-~~Documentation provided to these other owners may include, but is not limited to, power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings. The recipient will incorporate the applicable information into its PSCSs to evaluate whether changes are required.

The list of applicable changes provided in Requirement R3, Part 3.1 is inclusive, as it comprises either the protective equipment itself or the power system Elements that affect the coordination of Protection Systems. ~~-~~The drafting team recognizes that Facility changes at other locations can impact the PSCS of the Facility associated with the ~~Interconnected~~Interconnecting Element; e.g., the addition of a large autotransformer bank or generator not directly connected to the ~~Interconnected~~Interconnecting Element. The drafting team ~~believes~~contends that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. ~~-~~This is because the drafting team sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule~~ and confirm the changes are acceptable "prior to the in-service date," as stipulated by Requirement R4, Part 4.2~~.

Requirement R3, Part 3.2 allows for entities to agree upon a schedule, appropriate to the circumstances, for providing the details needed to conduct a PSCS or, absent such agreement, within 30 calendar days of a request for this information. This requirement provides a means for entities to receive requested information in a timely manner. In consideration of circumstances where the information may not be readily available or may be incomplete due the retirement of personnel, the purging of records, change of ownership, etc., it also provides the flexibility of mutually agreeing to a schedule for exchanging information. ~~-~~The drafting team ~~believes~~contends 30 calendar days after receipt of the request is a sufficient amount of time to provide the requested information where no other agreement exists.

~~Additionally, this requirement~~Requirement R3, Part 3.3 includes a provision for providing details associated with changes to the previously agreed-upon coordination when permanent changes are made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components. ~~-~~Based upon the limited number of instances that would occur under such circumstances, the drafting team ~~believes~~contends 30 calendar days after determining that changes are required is an appropriate time frame for providing the associated details to affected entities.

Requirement R4:

Requirement R4directs applicable entities, within 90 calendar days after receipt, to review the summary results of a PSCS or the technical justification, as described in Requirement R1, Part 1.2; and respond that they have reviewed and identified any issues. The drafting team contends 90 calendar days after receipt provides a reasonable time for the owners of Facilities to review.

Requirement R5:

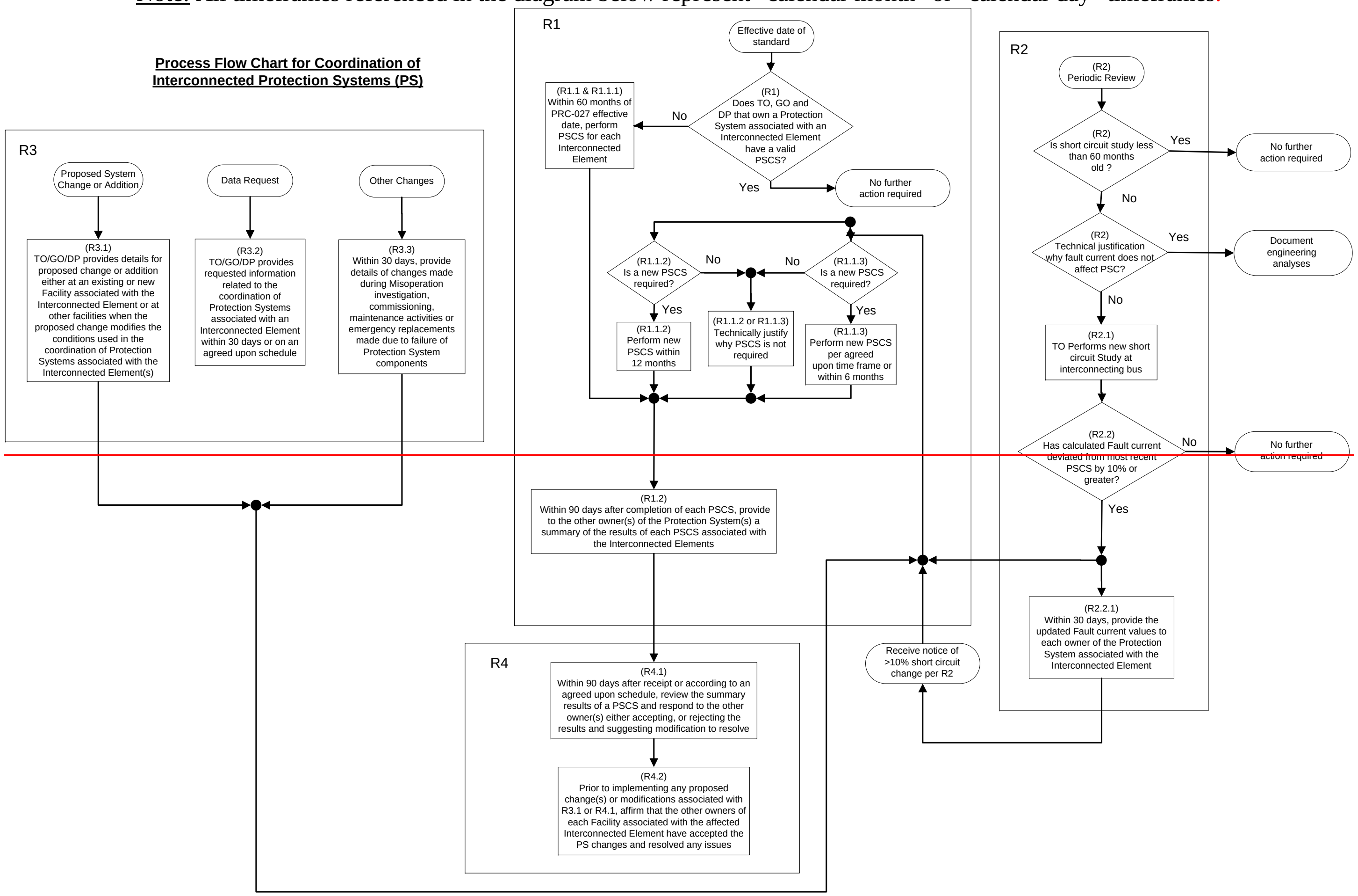
The reliability objective of this requirement is to bring the process of Protection System coordination full circle by ~~gaining the confirmation of interconnected entities that their Protection Systems are coordinated consistent with the purpose of this standard. Cooperative participation of Facility owners in communicating Protection System(s) design, and study results will achieve coordination of Protection Systems for reliable operation of the BES during Faults.~~ensuring owners of Protection System(s) associated with Interconnecting Elements have communicated and addressed any identified coordination issues prior to implementing changes in the Protection System(s) (in-service date).

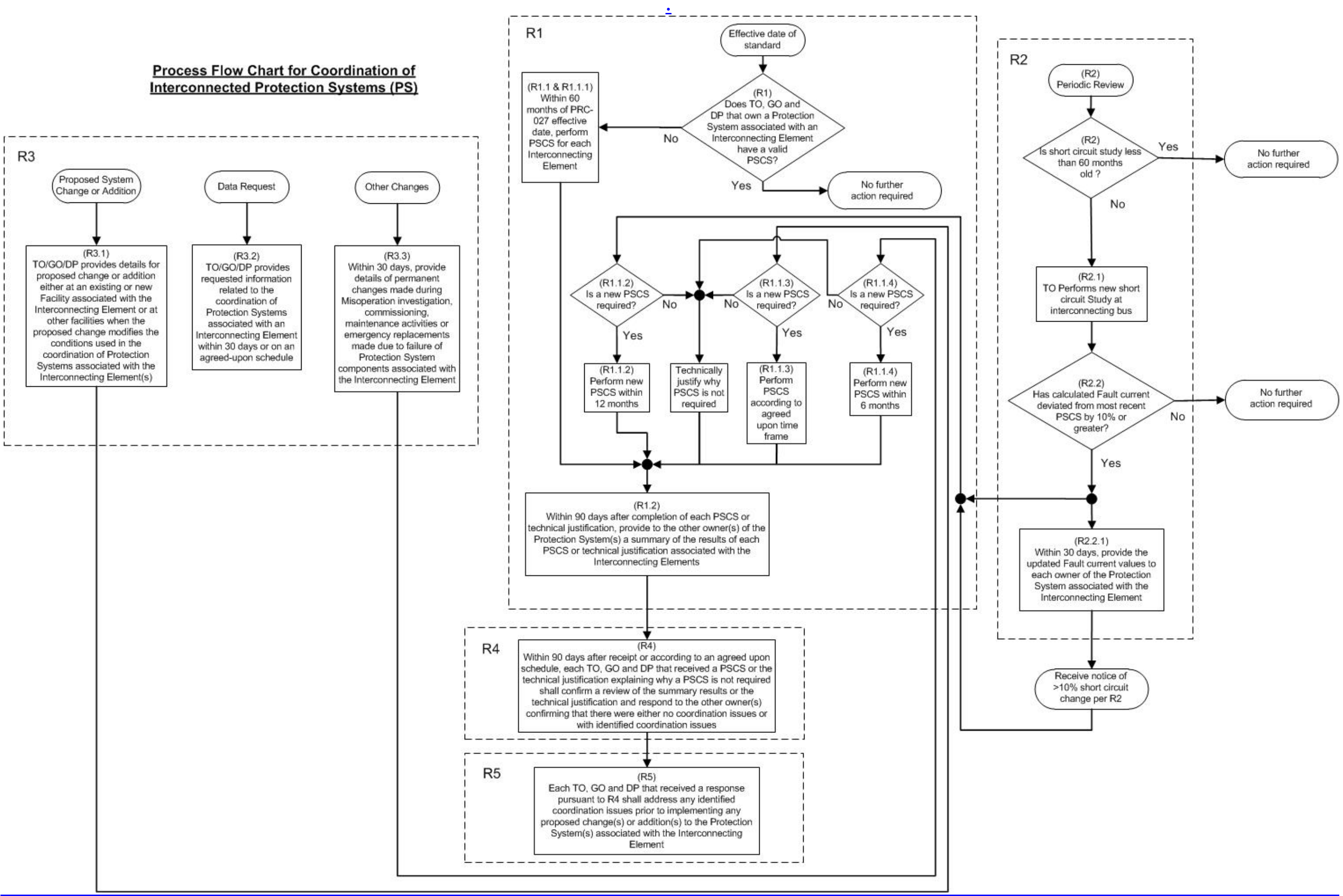
~~Requirement R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to review the summary results of a PSCS, as described in Requirement R1, Part 1.2; and respond as to whether they accepting or rejecting the results, and if rejecting, suggesting modifications to resolve any identified coordination issues. The drafting team believes 90 calendar days after receipt of the results of a PSCS provides a reasonable time for the owners of Facilities to review the summary results of a PSCS.~~

~~Requirement R4, Part 4.2 directs entities to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes as described in Requirement 3, Part 3.1 and Requirement 4, Part 4.1 prior to the in-service date of those changes. Any coordination issues identified during the review must be resolved prior to implementing the proposed changes. The purpose of Requirement 4, Part 4.2 is to assure the effects the proposed changes have on Protection Systems at a Facility associated with the Interconnected Element have been considered by all affected entities.~~

Application Guidelines

Process Flow Chart: Below is a complete representation of the process, including the relationships between requirements:
Note: All timeframes referenced in the diagram below represent "calendar month" or "calendar day" timeframes~~.~~




Process Flow Chart for Coordination of Interconnected Protection Systems (PS)
R1
Effective date of standard
(R1) Does TO, GO and DP that own a Protection System associated with an Interconnecting Element have a valid PSCS?
No
Yes
No further action required
(R1.1 & R1.1.1) Within 60 months of PRC-027 effective date, perform PSCS for each Interconnecting Element
(R1.1.2) Is a new PSCS required?
(R1.1.3) Is a new PSCS required?
(R1.1.4) Is a new PSCS required?
(R1.1.2) Perform new PSCS within 12 months
Technically justify why PSCS is not required
(R1.1.3) Perform PSCS according to agreed upon time frame
(R1.1.4) Perform new PSCS within 6 months
(R1.2) Within 90 days after completion of each PSCS or technical justification, provide to the other owner(s) of the Protection System(s) a summary of the results of each PSCS or technical justification associated with the Interconnecting Elements
R2
(R2) Periodic Review
(R2) Is short circuit study less than 60 months old ?
No further action required
(R2.1) TO Performs new short circuit Study at interconnecting bus
(R2.2) Has calculated Fault current deviated from most recent PSCS by 10% or greater?
(R2.2.1) Within 30 days, provide the updated Fault current values to each owner of the Protection System associated with the Interconnecting Element
Receive notice of >10% short circuit change per R2
R3
Proposed System Change or Addition
Data Request
Other Changes
(R3.1) TO/GO/DP provides details for proposed change or addition either at an existing or new Facility associated with the Interconnecting Element or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s)
(R3.2) TO/GO/DP provides requested information related to the coordination of Protection Systems associated with an Interconnecting Element within 30 days or on an agreed-upon schedule
(R3.3) Within 30 days, provide details of permanent changes made during Misoperation investigation, commissioning, maintenance activities or emergency replacements made due to failure of Protection System components associated with the Interconnecting Element
R4
(R4) Within 90 days after receipt or according to an agreed upon schedule, each TO, GO and DP that received a PSCS or the technical justification explaining why a PSCS is not required shall confirm a review of the summary results or the technical justification and respond to the other owner(s) confirming that there were either no coordination issues or with identified coordination issues
R5
(R5) Each TO, GO and DP that received a response pursuant to R4 shall address any identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element

Example Process

An example of the interaction between entities required to gather the information to perform an accurate study is provided below. This example is given as general guidance only and is not intended to represent all situations that may occur. More detailed examples are provided along with Figures 1-5 in the section that follows this example.

- The initiating entity (Entity A) will contact the ~~interconnected~~interconnecting entity (Entity B) and provide details of the ~~proposed~~ change(s) and may also request up-to-date Protection System information.
- Entities A and B will determine whether a new PSCS is required. In this example both agree that a new study is required. The study may be a joint study, individual studies, or a single study provided by Entity A and reviewed and approved by Entity B. In this example, the latter will occur.
- Upon receipt of the above request for information, Entity B will provide the information within 30 calendar days, or an agreed upon time frame.
- Entity A will perform a PSCS using the information received.
- Entity A will provide a summary of the results of the study to Entity B within 90 calendar days of completing the PSCS.
- Entity B will review the summary information and, within 90 calendar days of receiving the study results from Entity A, respond as to whether any coordination issues were identified, and if any further action is required.
    - In cases where the study reveals that changes to Protection Systems are needed, Entity B would propose to Entity A revisions that achieve acceptable results.
    - Ultimately, both entities will collaborate in developing a mutually acceptable solution.

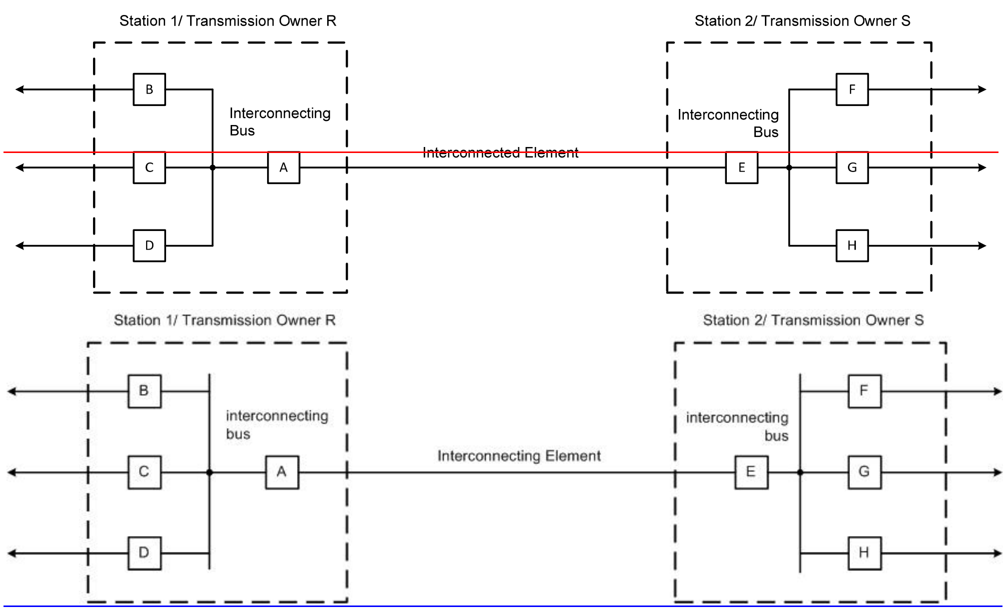
Diagrams

Introduction: The diagrams below are intended to provide guidance, to the owners of Facilities associated with the affected ~~Interconnected~~Interconnecting Element, for meeting the requirements of this standard. These examples are not intended to be inclusive of all situations and are based on the assumption that entities employ the appropriate engineering expertise and due diligence in developing settings for their Protection Systems. The examples given also assume a single owner as the initiator of a Protection System Coordination Study (PSCS) for the applicable ~~Interconnected~~Interconnecting Element. In actuality, any owner or owners may initiate the process. After the reviews of the PSCS or a summary of results, and prior to implementation of changes, the owners must work together to resolve any coordination issues identified during those reviews.

NOTES:

1. Protection System Coordination Studies are typically performed assuming maximum generation and all Facilities in service.
2. Protection Systems of the Transmission Owners, Generator Owners, and Distribution Providers described in the Figures and examples below do not include any systems or components enumerated in the 'Background Section' of this standard under "Other Aspects of Coordination of Protection Systems Addressed by Other Projects".
3. In the Figures below, the locations of the interconnecting bus(s) referenced in Requirement 2 are indicated.

Figure 1

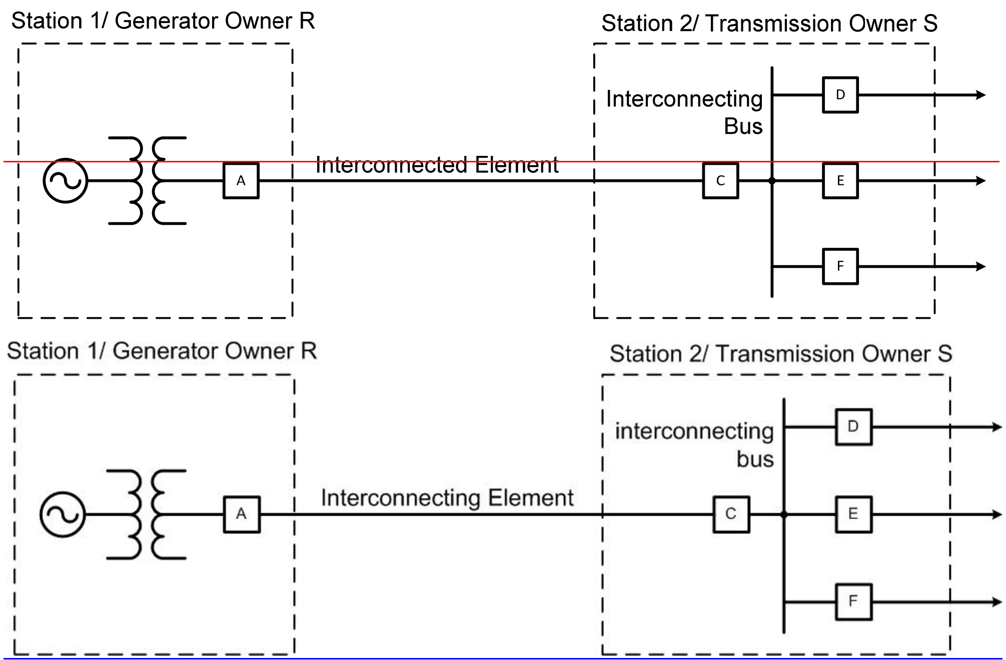


Application Guidelines

In Figure 1 above, the ~~Interconnected~~Interconnecting Element between the Transmission Owners is the transmission line between Breakers A and E.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 1, Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers E, F, G, and H. Likewise, Owner S is to develop~~ proposed~~ Protection System settings associated with Breaker E. Owner R is to review the Protection System settings associated with Breaker E (provided by Owner S) for coordination issues with the Protection System settings associated with Breakers A, B, C, and D.

Figure 2

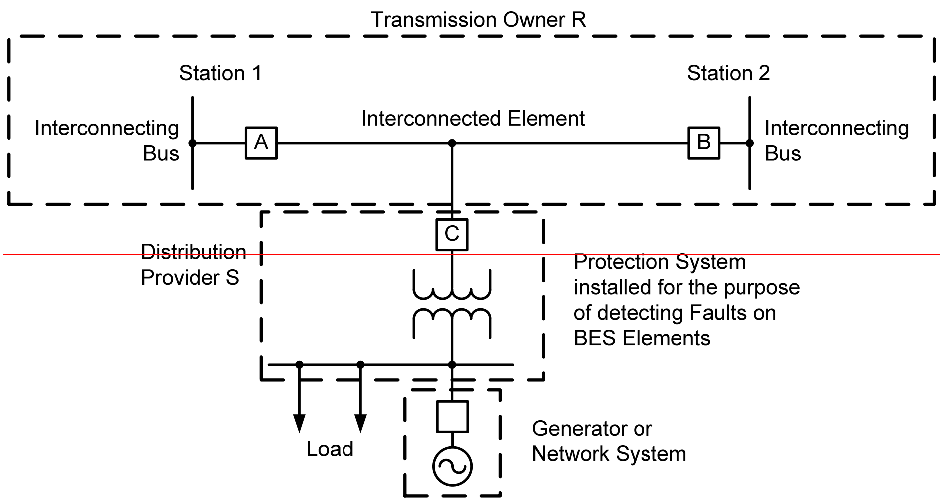


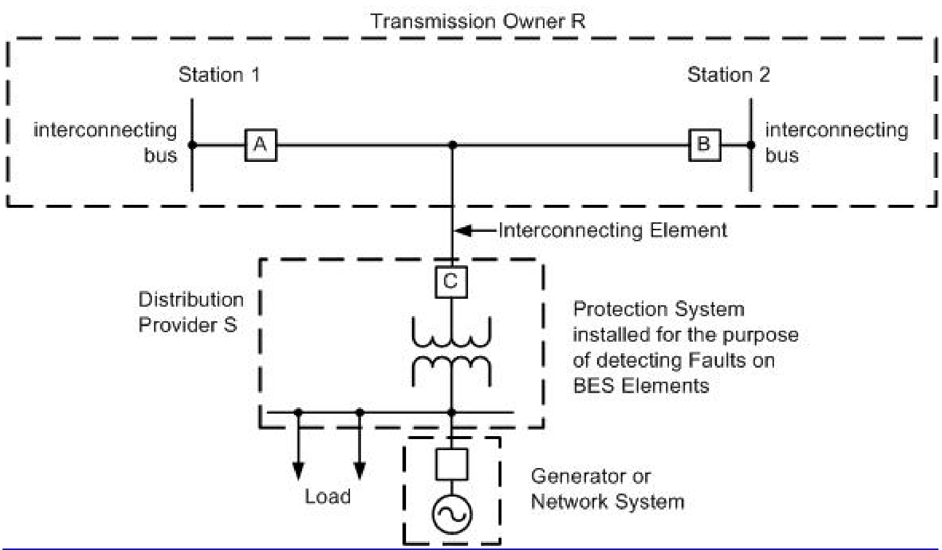
In Figure 2 above, the ~~Interconnected~~Interconnecting Element between the Transmission Owner and the Generator Owner is the transmission line or bus between Breakers A and C.

Note: Depending on the actual configuration and/or ownership, Breaker A may, or may not, exist as a GSU unit high-side breaker or a line breaker.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 2, Owner R is to develop ~~proposed~~ Protection System settings associated with Breaker A. Transmission Owner S is to review the Protection System settings associated with Breaker A (provided by Owner R) and the generator Protection Systems for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, Owner S is to develop ~~proposed~~ Protection System settings associated with Breaker C. ~~Generation~~ Generator Owner R is to review the Protection System settings associated with Breaker C (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A or the generator Protection Systems.

Figure 3





In Figure 3 above, the ~~Interconnected~~Interconnecting Element between the Transmission Owner and the Distribution Provider is the transmission line (or tap) between the Distribution Provider's Breaker C and the point of connection to the line between the Transmission Owner's Breakers A and B. Therefore, the applicable Protection Systems per this standard are those at Breakers A, B and C.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 3, Distribution Provider S is to develop ~~proposed~~ Protection System settings associated with Breaker C. Transmission Owner R is to review the Protection System settings associated with

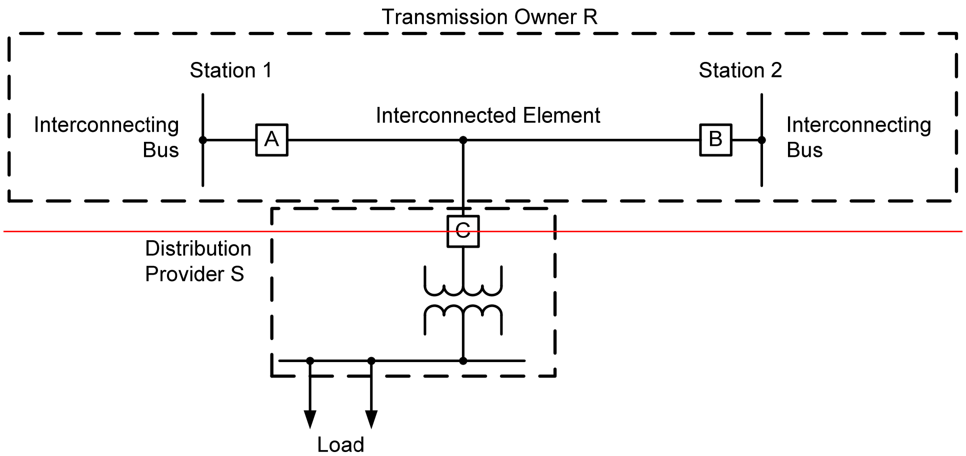
Line Breaker C (provided by Distribution Provider S) for coordination issues with the Protection System settings associated with Breakers A and B and other Protection Systems at stations 1 and 2.

Notes:

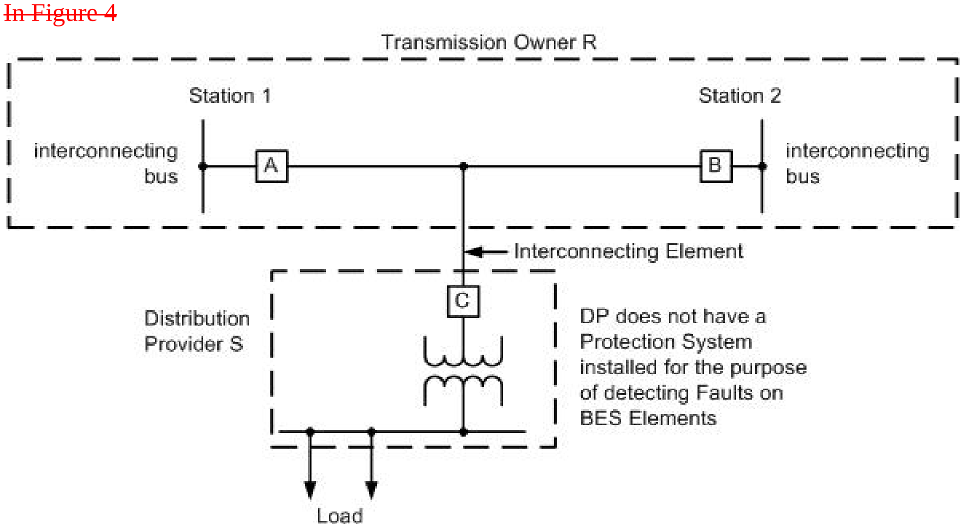
A PSCS is required per this standard for this example if a Protection System at the Distribution Provider's substation is installed for the purpose of detecting Faults on BES Elements.

Protection Systems installed for the purpose of detecting Faults on BES Elements do not include relays that, though they may operate for such Faults, are not installed specifically for that purpose. As an example, reverse power relays are often installed to detect situations where the transmission source for a power transformer becomes de-energized (for whatever reason) while the distribution bank remains energized from a source on the low-voltage side. In this case, the settings of the reverse power relay are typically calculated based on the charging current of the transformer from the low-voltage side. Although relays installed and set in this manner may operate as a result of a Fault on a BES Element, they are not specifically installed for the purpose of detecting that Fault.

Figure 4



~~In Figure 4~~



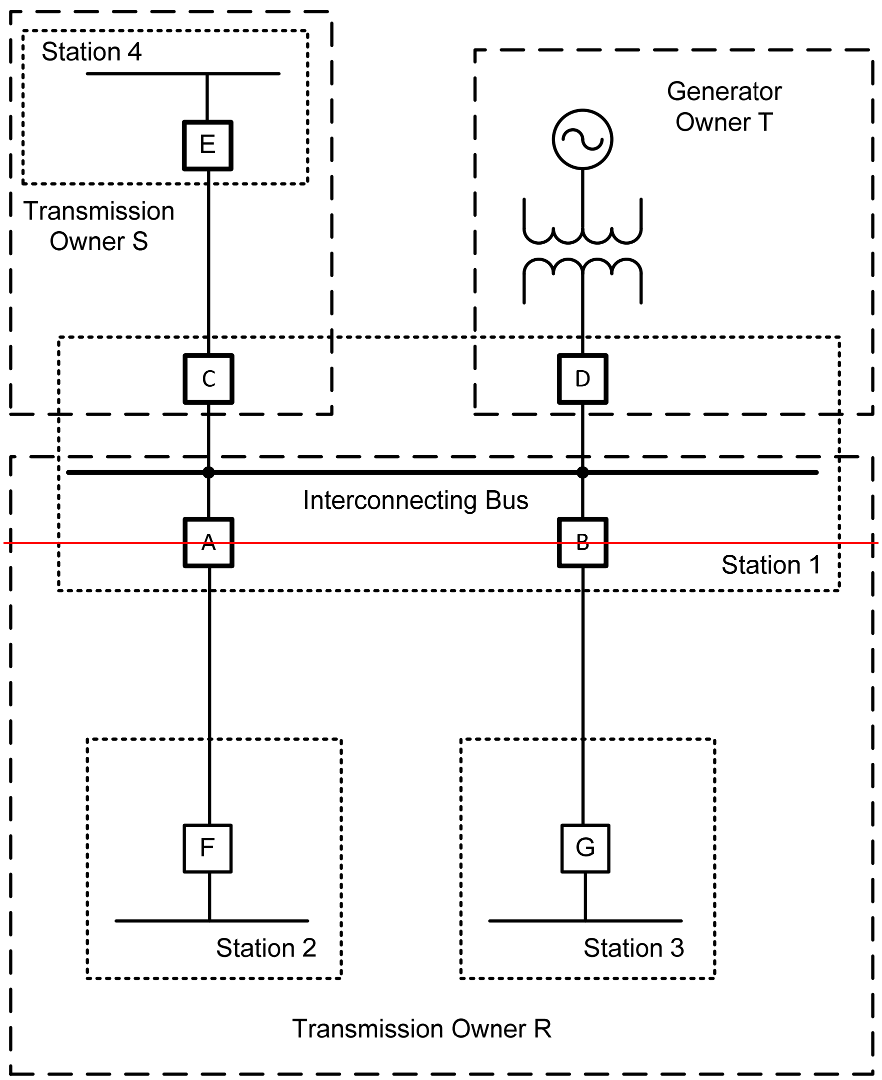
The configuration above~~, the Interconnected Element between the Transmission Owner and~~ is an example excluded from this standard because the Distribution Provider ~~is the transmission line or tap between the line and Breaker C.~~

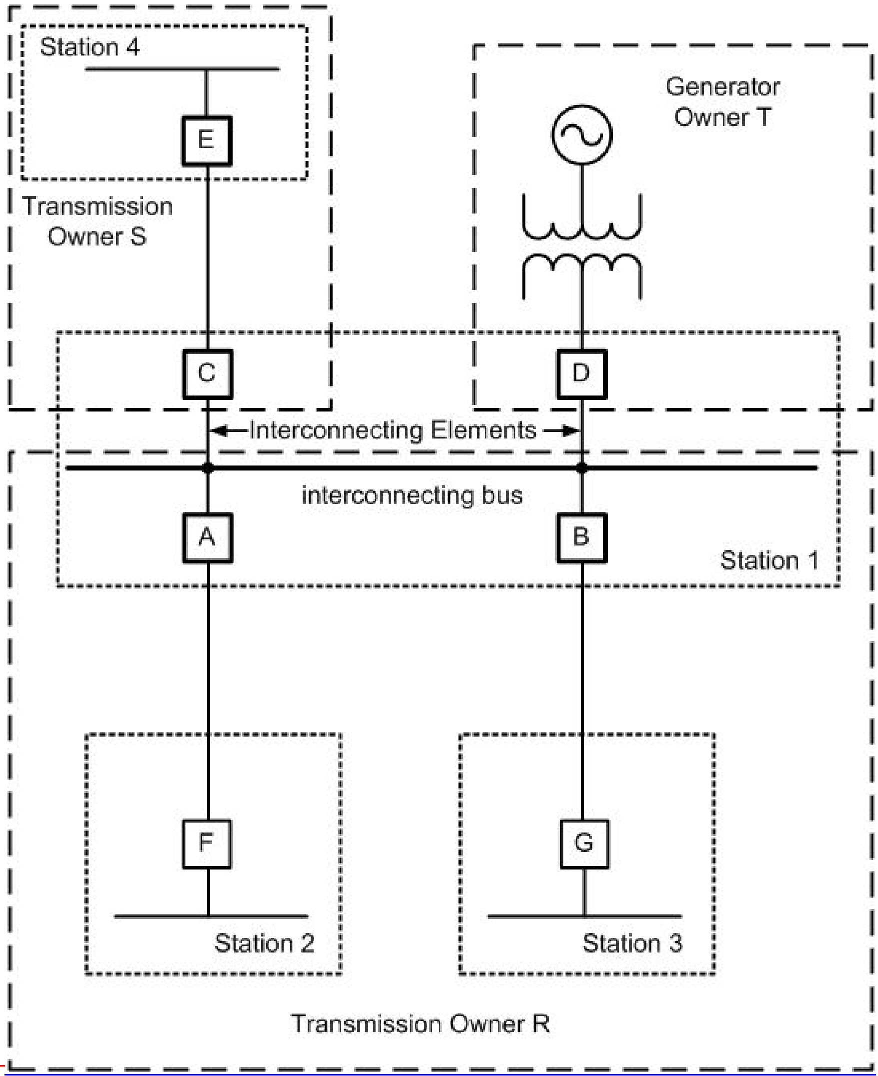
~~**Note:** No specific PSCS is required per this standard for this example since the~~S does not own Protection ~~System at the Distribution Provider's substation is not~~Systems installed for the purpose of detecting Faults on BES Elements.

Figure 5

Transmission/Generation Facility with Multiple Owners

Note: In a large majority of cases, Figure 2 would be applicable for most generator interconnections. In Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T.





~~In~~

Figure 5 above~~,~~ illustrates the ~~Interconnected Element~~Interconnecting Elements between the Transmission Owners R and S and Generator Owner T~~ is the common Transmission bus.~~. In this example, Transmission Owner S and Generator Owner T are not directly ~~interconnected~~interconnecting to each other at Station 1. All direct interconnections are between Owner R and each of the other Owners connected to the common bus at Station 1.

Example: For the purposes of conducting the PSCS associated with the Facilities in Figure 5:

Owner S is to develop ~~proposed~~ Protection System settings associated with Breakers C and E.

Owner T is to develop ~~proposed~~ Protection System settings associated with Breaker D, the generator, and its associated equipment.

Owner R is to develop ~~proposed~~ Protection System settings associated with Breakers A, B, F and G.

Owner R is to review the Protection System settings associated with Breaker C, E, D, and the generator Protection System (provided by Owners S and/or T) for coordination issues with the Protection System settings associated with Breakers A and B.

Owner S is to review the Protection System settings associated with Breakers A, F, B, G, D, and the generator Protection System (provided by Owners R and/or T) for coordination issues with the Protection System settings associated with Breaker C. To perform this review, it will be necessary that Transmission Owner R provide Owner S with its settings for Breakers A, F, B, and G, as well as the settings for Breaker D and generator Protection System settings provided to Owner R by Generator Owner T.

Owner T is to review the Protection System settings associated with Breakers A, F, B, G, C, and E (provided by Owners R and/or S) for coordination issues with the Protection System settings associated with Breaker D or the generator Protection System. In order to perform this review, it will be necessary that Transmission Owner R provide Generator Owner T with its settings for Breakers A, F, G, and B, as well as the settings for Breaker C and E provided to Owner R by Transmission Owner S.

Implementation Plan

Project 2007-06 System Protection Coordination PRC-027-1

Approvals Requested

- PRC-027-1 Protection System Coordination for Performance During Faults
- PRC-001-3 System Protection Coordination

Retirements Requested

- PRC-001-2 System Protection Coordination, Requirements R2 and R3

Applicable Entities

Standard	Applicable Entities					
	TO	GO	DP	TOP	GOP	BA
PRC-027-1: Protection System Coordination for Performance During Faults	X	X	X			
PRC-001-3: System Protection Coordination				X	X	X

Defined Terms

The standard drafting team proposes the following new definitions for use only within PRC-027-1:

Interconnecting Element
A Bulk Electric System (BES) Element that electrically joins Facilities:
a) owned by separate Registered Entities, or
b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Transmission Owner, Generator Owner, or Distribution Provider)

Protection System Coordination Study
A study documenting that existing or proposed Protection Systems operate in the intended sequence for clearing Faults.

Background

On December 7, 2006, the NERC Planning Committee approved the assessment of Standard PRC-001-1 (System Protection Coordination) prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF asserted:

> *"The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the 'operating horizon, operations planning horizon, and planning horizon' protection coordination issues, the deficiencies in the current standard are magnified."*

And further:

> *"The SPCTF… recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards."*

The Standard Committee approved the Standard Authorization Request with modifications by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

With the development of the proposed Reliability Standard PRC-027-1, the Standard Drafting Team (SDT) for Project 2007-06 – System Protection Coordination, has addressed observations and recommendations of the NERC SPCTF assessment of PRC-001-1 by:

1. Incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) and moving those requirements into a new standard (as recommended by the SPCTF assessment), focusing on the performance of Protection Systems during Faults.
2. Assigning responsibility for coordination of Protection Systems during Faults to the appropriate functional entities – the Protection System equipment owners, specifically: Transmission Owners, Generator Owners, and Distribution Providers.
3. Transferring the responsibility of addressing the three operating horizon Requirements R2, R5, and R6 of PRC-001-1 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standard(s) within that project. (The NERC Board of Trustees approved these changes proposed by the Project 2007-03 team when it approved PRC-001-2 on May 9, 2012.)

Effective Date of New or Revised Standards

PRC-027-1 – Protection System Coordination for Performance During Faults

PRC-027-1 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

PRC-001-3 – System Protection Coordination

PRC-001-3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Effective Date for Definitions

The two proposed definitions “Interconnecting Element” and “Protection System Coordination Study” shall each become effective concurrently with PRC-027-1.

Retirement

PRC-001-2 – System Protection Coordination shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter that is twelve (12) months after the date that the PRC-001-3 is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, PRC-001-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter that is twelve (12) months after the date that the PRC-001-3 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan

Project 2007-06 System Protection Coordination PRC-027-1

Approvals Requested

- PRC-027-1 Protection System Coordination for Performance During Faults
- PRC-001-3 System Protection Coordination

Retirements Requested

- PRC-001-2 System Protection Coordination, Requirements R2 and R3

Applicable Entities

Standard	Applicable Entities					
	TO	GO	DP	TOP	GOP	BA
PRC-027-1: Protection System Coordination for Performance During Faults	X	X	X			
PRC-001-3: System Protection Coordination				X	X	X

Defined Terms ~~in the NERC Glossary~~

The standard drafting team proposes the following new definitions for use only within PRC-027-1~~, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms~~:

Interconnecting Element~~:~~

A Bulk Electric System (BES) Element that electrically joins ~~facilities~~Facilities:

a) owned by separate Registered Entities, or

b) owned by the same Registered Entity that represents multiple functional entity responsibilities (~~Distribution Provider~~Transmission Owner, Generator Owner, or ~~Transmission Owner~~Distribution Provider)

Protection System Coordination Study~~:~~

A study documenting that ~~demonstrates~~ existing or proposed Protection Systems operate in the ~~desired~~intended sequence for clearing Faults.

Background

On December 7, 2006, the NERC Planning Committee approved the assessment of Standard PRC-001-1 (System Protection Coordination) prepared by the NERC System Protection and Control Task Force (SPCTF). The SPCTF asserted:

> *"The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the 'operating horizon, operations planning horizon, and planning horizon' protection coordination issues, the deficiencies in the current standard are magnified."*

And further:

> *"The SPCTF… recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards."*

The Standard Committee approved the Standard Authorization Request with modifications by the SPCTF for posting on June 5, 2007. The SAR was posted for comment from June 11, 2007 – July 10, 2007, and was subsequently approved.

With the development of the proposed Reliability Standard PRC-027-1, the Standard Drafting Team (SDT) for Project 2007-06 – System Protection Coordination, has ~~followed the~~addressed observations and ~~recommendation~~recommendations of the NERC SPCTF assessment of PRC-001-1~~ which had six requirements. The SDT accomplishes this~~ by:

1. Incorporating and building upon the elements of the two planning horizon Requirements R3 and R4 of PRC-001-1 (now R2 and R3 of PRC-001-2) and moving those requirements into a new standard (as recommended by the SPCTF assessment), focusing on the performance of Protection Systems during Faults.
2. Assigning responsibility for coordination of Protection Systems during Faults to the appropriate functional entities – the Protection System equipment owners, specifically: Transmission Owners, Generator Owners, and Distribution Providers.
3. Transferring the responsibility of addressing the three operating horizon Requirements R2, R5, and R6 of PRC-001-1 to Project 2007-03 Real-time Operations for inclusion in the revisions of the appropriate operating standard(s) within that project. (The NERC Board of Trustees approved these changes proposed by the Project 2007-03 team when it approved PRC-001-2 on May 9, 2012.)
4. ~~Leaving the legacy Requirement R1 of PRC-001-2 in PRC-001-3 (thereby not creating a reliability gap) until it is incorporated into a new or revised reliability standard.~~

   ~~Note: The drafting team added Measure (M1) to PRC-001-3 related to Requirement R1.~~

Effective Date of New or Revised Standards~~ and Definitions~~

PRC-027-1 ~~-~~– Protection System Coordination for Performance During Faults

PRC-027-1 shall become effective on the first day of the first calendar quarter that is twelve (12) months ~~beyond~~after the date that ~~this~~the standard is approved by an applicable ~~regulatory authorities. In those jurisdictions~~governmental authority or as otherwise provided for in a jurisdiction where ~~regulatory approval~~approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months ~~beyond~~after the date ~~this~~the standard is ~~approved~~adopted by the NERC Board of Trustees~~,~~ or as otherwise ~~made effective pursuant to the laws applicable to such ERO governmental authorities. For Interconnected Elements between Canadian Facilities (~~provided for in that ~~recognize the NERC Board of Trustees or other ERO governmental authority approval) and U.S. Facilities (that recognize FERC approval), the effective date shall be the FERC-approved effective date~~jurisdiction.

PRC-001-3 – System Protection Coordination

~~Same effective date as PRC-027-1.~~
PRC-001-3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Effective Date for Definitions

The two proposed definitions ~~(Interconnected Facilities~~"Interconnecting Element" and "Protection System Coordination Study~~)~~" shall each become effective ~~at the same time as~~ concurrently with PRC-027-1.

Retirement~~:~~

~~PRC-001-2 – Protection System Coordination shall be retired at midnight the day before PRC-001-3 becomes effective.~~

PRC-001-2 – System Protection Coordination shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter that is twelve (12) months after the date that the PRC-001-3 is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, PRC-001-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter that is twelve (12) months after the date that the PRC-001-3 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Unofficial Comment Form

Project 2007-06 System Protection Coordination
4th Draft of PRC-027-1

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the 4th draft of the standard PRC-027-1: Protection System Coordination for Performance During Faults. Comments must be submitted by **8 p.m. Eastern December 18, 2013**. If you have questions please contact Al McMeekin or by telephone at 803-530-1963.

http://www.nerc.com/pa/Stand/Pages/Project-2007-06-System-Protection-Coordination.aspx

Background Information:
The Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted the third draft of Reliability Standard PRC-027-1 "Protection System Coordination for Performance During Faults" for comment from June 4, 2013 to July 3, 2013. The drafting team considered all stakeholder comments and suggestions and revised the draft standard. The following is a summary of changes the drafting team made:

- Changed the term "Interconnected Element" to "Interconnecting Element"
- Re-arranged the definition of "Interconnecting Element" for clarity and spelled out "Bulk Electric System" rather than using the acronym "BES"
- Modified the definition of " Protection System Coordination Study" replacing the words "that demonstrates" with "documenting that" and "desired" with "intended"
- Changed the word "desired" to "intended" in the Purpose
- Added the parenthetical phrase "(that own Protection Systems identified in the Facilities section 4.2 below)" to Applicability section 4.1.3 "Distribution Provider"
- The "Other Aspects of Coordination of Protection Systems Addressed by Other Projects" section was moved from the "Background" section to the "Roadmap" section of the standard
- Removed the technical justification for not conducting the Fault current review specified in Requirement R2 and the associated Measure M3
- Modified Requirement 4 and split it into two Requirements, R4 and R5 for clarity
- Requirement R5 mandates that any identified coordination issues be addressed prior to the implementation of any changes or additions to the Protection System(s) associated with the Interconnecting Element
- The VSLs were modified for consistency with the revised requirements
- The Guidelines and Technical Basis section was modified to reflect corresponding changes in the standard
- The Process Flow Chart was updated to reflect changes made to the standard
- The Figures and associated descriptions were modified to provide more clarity

In June of 2013, the Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) posted Draft 3 of PRC-027-1 for comment and ballot. The SPCSDT is recommending retirement of Requirements R2 and R3 of PRC-001-2 because the reliability objectives of those two requirements are addressed in the new Reliability Standard PRC-027-1 — Protection System Coordination for Performance During Faults, leaving only one requirement in PRC-001-3. Attempting to provide clarity, the SPCSDT included PRC-001-3 in the June posting with a revised Applicability section and a measure for the lone Requirement R1. However, since that posting, the Independent Experts Review Panel (Independent Experts) released its Final Report and Requirements Scoring Spreadsheet which reviewed and assessed the content and quality of the NERC Reliability Standards. The Independent Experts concluded that PRC-001-2, Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC's Reliability Standards be consolidated. Because Requirement R1 of PRC-001-3 was identified as appropriate in another body of standards and will be included in the review for consolidation, the requirement will remain unchanged pending ongoing work to implement the Independent Experts recommendations. NERC standards staff is currently reviewing how to address these recommendations and industry concerns with Requirement R1. Consequently, a draft of PRC-001-3 reflecting only the removal of Requirements R2 and R3, and updated pro forma language for the "Effective Date" and "Compliance" sections of the standard is included with this fourth posting of PRC-027-1.

Note: The SPCSDT is not soliciting comments on PRC-001-3 because of the limited changes discussed above.

The SPCSDT is soliciting stakeholder feedback on draft 4 of PRC-027-1 during a 45-day formal comment period with parallel ballot.

Question

Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. Please provide any issues you have with this draft of PRC-027-1 along with a proposed solution.

Comments:

Project 2007-06 System Protection Coordination Mapping Document

Mapping Document Showing Translation of PRC-001-2 — System Protection Coordination to PRC-027-1 — Protection System Coordination for Performance During Faults

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	Retained in PRC-001-3	N/A
R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R2.1** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. **R2.2** Each Transmission Operator shall coordinate all new protective systems and	PRC-027-1: R1, R2, R3, R4 & R5 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Coordination Study (PSCS) for each of its Interconnecting Elements as follows: **1.1.1.** Within 60 calendar months after the effective date of this standard, if no PSCS for that Interconnecting Element exists. **1.1.2.** Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required.

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
all protective system changes with neighboring Transmission Operators and Balancing Authorities.		**1.1.3.** According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or technically justify why such a study is not required. **1.1.4.** Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3, or technically justify why such a study is not required. **1.2.** Within 90 calendar days after the completion of each PSCS or the technical justification pursuant to Requirement R1, Part 1.1, provide to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s): a summary of the results of each PSCS performed, including, at a minimum, the Protection Systems reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed; or the technical justification. **R2.** For each Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months: **2.1.** Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at its interconnecting bus where a PSCS is available pursuant to Requirement R1. **2.2.** Calculate the percent change between the Fault current values (single line to ground and 3-phase for its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		determined pursuant to Requirement R2, Part 2.1, using the following equation: $$\% \, Change = \left\| \frac{Iscs - Ipscs}{Ipscs} \right\| x \; 100$$ Where : I_{scs} = Fault current value from present short circuit study And: I_{pscs} = Fault current value used in the most recent PSCS **2.2.1** Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (Iscs) to each owner of the Protection System(s) associated with the Interconnecting Element. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnecting Element: **3.1.** Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s). • New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		• Changes to a transmission system Element that alter any sequence or mutual coupling impedance • Changes to generator unit(s) that result in a change in impedance • Changes to the generator step-up transformer(s) that result in a change in impedance **3.2.** Requested information related to the coordination of Protection Systems associated with an Interconnecting Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule. **3.3.** Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a summary of the results of a PSCS or a technical justification explaining why a PSCS is not required (pursuant to Requirement R1, Part 1.2) shall, within 90 calendar days after receipt or according to an agreed upon schedule, review the summary of the results or the technical justification, and respond to the other owner(s) either: • Confirming that the summary of the results was reviewed and no coordination issue(s) were identified, or • Confirming that the summary of the results was reviewed and any

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		identified coordination issue(s) were noted, or • Confirming that a technical justification was reviewed and no issue(s) were identified, or • Confirming that a technical justification was reviewed and any identified issue(s) were noted **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a response pursuant to Requirement R4 shall address any identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element.
R3. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	PRC-027-1: R1, R2, R3, R4 & R5 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Coordination Study (PSCS) for each of its Interconnecting Elements as follows: **1.1.1.** Within 60 calendar months after the effective date of this standard, if no PSCS for that Interconnecting Element exists. **1.1.2.** Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. **1.1.3.** According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		Requirement R3, Part 3.1, or technically justify why such a study is not required. **1.1.4.** Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3, or technically justify why such a study is not required. **1.2.** Within 90 calendar days after the completion of each PSCS or the technical justification pursuant to Requirement R1, Part 1.1, provide to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s): a summary of the results of each PSCS performed, including, at a minimum, the Protection Systems reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed; or the technical justification. **R2.** For each Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months: **2.1.** Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at its interconnecting bus(s) where a PSCS is available pursuant to Requirement R1. **2.2.** Calculate the percent change between the Fault current values (single line to ground and 3-phase for its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation:

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		$$\% \; Change = \left\lvert \frac{Iscs - Ipscs}{Ipscs} \right\rvert x \; 100$$ Where : I_{scs} = Fault current value from present short circuit study And: I_{pscs} = Fault current value used in the most recent PSCS **2.2.1** Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (Iscs) to each owner of the Protection System(s) associated with the Interconnecting Element. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same Interconnecting Element: **3.1.** Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s). • New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios • Changes to a transmission system Element that alter any sequence or mutual coupling impedance

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		• Changes to generator unit(s) that result in a change in impedance • Changes to the generator step-up transformer(s) that result in a change in impedance **3.2.** Requested information related to the coordination of Protection Systems associated with an Interconnecting Element within 30 calendar days of receiving a request or according to an agreed-upon schedule. **3.3.** Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a summary of the results of a PSCS or a technical justification explaining why a PSCS is not required (pursuant to Requirement R1, Part 1.2) shall, within 90 calendar days after receipt or according to an agreed upon schedule, review the summary of the results or the technical justification, and respond to the other owner(s) either: • Confirming that the summary of the results was reviewed and no coordination issue(s) were identified, or • Confirming that the summary of the results was reviewed and any identified coordination issue(s) were noted, or • Confirming that a technical justification was reviewed and no

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		issue(s) were identified, or • Confirming that a technical justification was reviewed and any identified issue(s) were noted **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a response pursuant to Requirement R4 shall address any identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element.

Project 2007-06 System Protection Coordination Mapping Document

Mapping Document Showing Translation of PRC-001-2 ~~-~~— System Protection Coordination to PRC-027-1 ~~-~~— Protection System Coordination for Performance During Faults.

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	Retained in PRC-001-3	N/A
R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R2.1** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. **R2.2** Each Transmission Operator shall coordinate all new protective systems and	PRC-027-1~~,~~: R1, R2, R3, ~~&~~ R4 & R5 Note: Applicability changed to GO, TO and DP	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Coordination Study (PSCS) for each of its ~~Interconnected Element on its System~~Interconnecting Elements as follows: **1.1.1.** Within 60 calendar months after the effective date of this standard, if no PSCS for that Interconnecting Element exists. **1.1.2.** Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
all protective system changes with neighboring Transmission Operators and Balancing Authorities.		is not required. **1.1.3.** According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or ~~within~~technically justify why such a study is not required. **1.1.4.** Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3, or technically justify why such a study is not required. **1.2.** Within 90 calendar days after the completion of each PSCS or the technical justification pursuant to Requirement R1, Part 1.1, provide to the other owner(s) of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element(s~~),~~): a summary of the results of each PSCS performed ~~pursuant to Requirement R1, Part 1.1, (~~, including, at a minimum, the Protection Systems reviewed, the associated Fault ~~currents~~current(s) used, any issues identified, and any revisions or actions proposed~~).~~; or the technical justification. **R2.** For each Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months: **2.1.** Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at its interconnecting bus where a PSCS is available pursuant to Requirement R1. **2.2.** Calculate the percent change between the Fault current values (single

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		line to ground and 3-phase for its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation: $$\% \, Change = \left\| \frac{Iscs - Ipscs}{Ipscs} \right\| x \; 100$$ Where : I_{scs} = Fault current value from present short circuit study And: I_{pscs} = Fault current value used in the most recent PSCS **2.2.1** Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (Iscs) to each owner of the Protection System(s) associated with the Interconnecting Element. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same ~~Interconnected~~Interconnecting Element: **3.1.** Details for any proposed change or addition listed below; either at an existing or new Facility associated with the ~~Interconnected~~Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the ~~Interconnected~~Interconnecting Element(s). • New installation, replacement with different types, or modification

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		of~~:~~ protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios • Changes to a transmission system Element that alter any sequence or mutual coupling impedance • Changes to generator unit(s) that result in a change in impedance • Changes to the generator step-up transformer(s) that result in a change in impedance **3.2.** Requested information related to the coordination of Protection Systems associated with an ~~Interconnected~~Interconnecting Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule. **3.3.** Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider ~~shall~~that received a summary of the results of a PSCS or a technical justification explaining why a PSCS is not required (pursuant to Requirement R1, Part 1.2) shall, within 90 calendar days after receipt or according to an agreed upon schedule, review the summary of the results or the technical

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		justification, and respond to the other owner(s) either: • ~~**4.2.** Prior~~Confirming that the summary of the results was reviewed and no coordination issue(s) were identified, or • Confirming that the summary of the results was reviewed and any identified coordination issue(s) were noted, or • Confirming that a technical justification was reviewed and no issue(s) were identified, or • Confirming that a technical justification was reviewed and any identified issue(s) were noted **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a response pursuant to Requirement R4 shall address any identified coordination issues prior to implementing any proposed change(s) or ~~modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted~~addition(s) to the Protection System(s) ~~changes including the resolution of any identified coordination issues~~associated with the Interconnecting Element.
R3. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing	PRC-027-1~~,~~: R1, R2, R3, ~~&~~ R4 & R5 Note: Applicability	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1.** Perform a Protection System Coordination Study (PSCS) for each of its ~~Interconnected Element on its System~~ Interconnecting Elements as follows:

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
Authorities.	changed to GO, TO and DP	**1.1.1.** Within 60 calendar months after the effective date of this standard, if no PSCS for that ~~Interconnected~~Interconnecting Element exists. **1.1.2.** Within 12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. **1.**~~**2.** Within 90 calendar days after the completion of each PSCS provide to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s), a summary of the results of each PSCS performed pursuant to Requirement R1, Part 1.1, (including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed).~~**1.3.** According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or technically justify why such a study is not required. **1.1.4.** Within six calendar months of being notified of a change as described in Requirement R3, Part 3.3, or technically justify why such a study is not required. **1.2.** Within 90 calendar days after the completion of each PSCS or the technical justification pursuant to Requirement R1, Part 1.1, provide to the other owner(s) of the Protection System(s) associated with the

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		Interconnecting Element(s): a summary of the results of each PSCS performed, including, at a minimum, the Protection Systems reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed; or the technical justification. **R2.** For each ~~Interconnected~~Interconnecting Element on its System, the Transmission Owner shall, once every 60 calendar months~~, technically justify why Fault current does not affect the Protection System coordination, or~~: **2.1.** Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at ~~the~~its interconnecting bus(s) where a ~~Protection System Coordination Study~~ ~~(~~PSCS~~)~~ is available ~~per~~pursuant to Requirement R1. **2.2.** Calculate the percent change between the Fault current values (single line to ground and 3-phase for ~~the~~its interconnecting bus(s) under consideration) used in the most recent PSCS and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation: $$\% \, Change = \left\| \frac{Iscs - Ipscs}{Ipscs} \right\| x \; 100$$ Where : I_{scs} = Fault current value from present short circuit study And: I_{pscs} = Fault current value used in the most recent PSCS **2.2.1** Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		the updated Fault current values (Iscs) to each owner of the Protection System(s) associated with the ~~Interconnected~~Interconnecting Element. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall provide to each Transmission Owner, Generator Owner, and Distribution Provider connected to the same ~~Interconnected~~Interconnecting Element: **3.1.** Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s). • New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios • Changes to a transmission system Element that alter any sequence or mutual coupling impedance • Changes to generator unit(s) that result in a change in impedance • Changes to the generator step-up transformer(s) that result in a change in impedance **3.2.** Requested information related to the coordination of Protection Systems associated with an ~~Interconnected~~Interconnecting Element within 30 calendar days of receiving a request or according to an agreed-

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		upon schedule. **3.3.** Within 30 calendar days of making the change, details of permanent changes made to Protection Systems associated with the Interconnecting Element during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a summary of the results of a PSCS or a technical justification explaining why a PSCS is not required (pursuant to Requirement R1, Part 1.2) shall~~:~~ ~~**4.1.** Within~~, within 90 calendar days after receipt~~,~~ or according to an agreed upon schedule, review the summary of the results ~~of a PSCS (per Requirement R1, Part 1.2)~~or the technical justification, and respond to the other owner(s~~):~~) either: ~~• Accepting~~Confirming that the ~~results, or~~ • ~~• Rejecting~~summary of the results was reviewed and ~~suggesting modifications to resolve~~no coordination issue(s) were identified, or • Confirming that the summary of the results was reviewed and any identified coordination issue(s) were noted, or • Confirming that a technical justification was reviewed and no issue(s) were identified, or

Standard: PRC-001-2 - System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language or Comment in PRC-027-1**
		• Confirming that a technical justification was reviewed and any identified issue(s) were noted **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that received a response pursuant to Requirement R4 shall address any identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element.

Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 — Protection System Coordination for Performance During Faults

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1 — Protection System Coordination for Performance During Faults.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

The System Protection Coordination Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures; nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines
Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.
In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and, therefore, concentrated its approach on the reliability impact of the requirements.

PRC-027-1 Protection System Coordination for Performance During Faults is a new Reliability Standard with the stated purpose: "*To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.*" PRC-027-1 has five (5) requirements that incorporate and clarify the reliability intent of Requirements R2 and R3 of PRC-001-2. The new standard addresses the aspects of coordination for new and changes to existing Protection Systems, as well as requiring an initial and periodic review of existing Protection Systems. The new requirements describe the steps necessary to achieve coordination. The coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner, reviewing each others' Protection System settings and schemes, and resolving any identified coordination issues.

All five requirements are assigned VRFs of Medium. The assignment of the Medium VRFs was made based on the premise that failure to perform these coordination activities by themselves would not directly cause or contribute to bulk power system instability, separation, or a Cascading sequence of failures. For a requirement to be assigned a "High" VRF, there should be the expectation that failure to meet the required performance "will" result in instability, separation, or Cascading failures, and this is usually not the case when an applicable entity fails to 'coordinate' activities. While the SDT agrees that, under some circumstances, it is possible that a failure to perform the required activities may hinder the coordination process; however, the failure would not, by itself, result in instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-027-1, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to perform a Protection System Coordination Study for each Interconnecting Element to verify that Protection Systems components operate in the intended sequence during Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R1 is similar in scope to Requirements R2, R3, R4 and R5, as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R1 directs that Protection System Coordination Studies are performed for every Interconnecting Element to verify coordination of existing Protection Systems. This requirement is similar to Requirement R1 of FAC-002-1, which also requires studies be performed and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to perform a Protection System Coordination Study for each Interconnecting Element to verify that Protection Systems components operate in the intended sequence during Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R1 does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by less than or equal to	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 20 calendar days but less than or	The responsible entity performed a Protection System Coordination Study on an Interconnecting Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required but was late by more than 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar days.

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
10 calendar days.	equal to 20 calendar days.	equal to 30 calendar days.	OR The responsible entity failed to perform a Protection System Coordination Study on an Interconnected Element in accordance with Requirement R1, Parts 1.1.1, 1.1.2, 1.1.3, or 1.1.4. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2, 1.1.3, or 1.1.4. OR The responsible entity failed to provide a summary of the results of each Protection System Coordination Study or a technical justification in accordance with Requirement R1, Part 1.2.

VSL Justifications – PRC-027-1, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to periodically perform a short circuit study to calculate the percent change in Fault current values used as inputs for updating Protection System Coordination Study(s), and to provide the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s) updated Fault current values, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R2 is similar in scope to Requirements R1, R3, R4 and R5 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R2 facilitates a periodic review of Fault currents, and notification of owner(s) of the Protection System(s) associated with the Interconnecting Element(s). This requirement is similar to Requirement R6 of BAL-005-0.2b in that it also requires the comparison of calculated data and possible notification of other entities; and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to periodically perform a short circuit study to calculate the percent change in Fault current values used as inputs for updating Protection System Coordination Study(s), and to provide the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s) updated Fault current values, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R2 does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner performed a short circuit study, as required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 90 calendar days. OR The Transmission Owner failed to perform a short circuit study, as required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent change between the Fault currents, according to the equation designated in Requirement R2, Part 2.2. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnecting Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnected Element, the updated Fault current values, as required in Requirement R2, Part 2.2.1.

VSL Justifications – PRC-027-1, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to communicate proposed change(s) or addition(s) that modify the conditions used in the coordination of Protection System(s) associated with an Interconnecting Element or provide requested information needed to conduct a Protection System Coordination Study could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R3 is similar in scope to Requirements R1, R2, R4 and R5 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R3 facilitates the provision of pertinent information regarding proposed changes that could impact the coordination of Protection Systems associated with an Interconnecting Element, or information needed to do a Protection System Coordination Study. This requirement is similar to Requirement R8 of FAC-008-3 in that it also requires the provision of reliability data to other pertinent functional entities, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to communicate proposed change(s) or addition(s) that modify the conditions used in the coordination of Protection System(s) associated with an Interconnecting Element or provide requested information needed to conduct a Protection System Coordination Study could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R3 does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R3			
Lower	**Moderate**	**High**	**Severe**
			The responsible entity failed to provide the owner(s) of the Facility associated with the Interconnecting Element, details for any proposed change(s) or addition(s) identified in Requirement R3, Part 3.1. OR
The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the information required in Requirement R3, Part 3.3.

VSL Justifications – PRC-027-1, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to review a summary of the results of a PSCS or a technical justification and respond to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s) in a timely manner could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R4 is similar in scope to Requirements R1, R2, R3 and R5 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R4 mandates responsible entities review a Protection System Coordination Study summary or a technical justification to determine if there are any issue(s) associated with any proposed change(s) to the pertinent Protection System(s), and communicate those findings to the sender. This requirement is similar to Requirement R1 of FAC-002-1 in that it requires coordination and cooperation of assessments, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to review a summary of the results of a PSCS or a technical justification and respond to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s) in a timely manner could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R4 does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following receipt of the Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4.	The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following receipt of the Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4.	The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following receipt of the Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4.	The responsible entity responded in more than 120 calendar days following receipt of the Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4. OR The responsible entity failed to review the Protection System Coordination Study summary of the results, or the technical justification provided to them in accordance with Requirement R4. OR The responsible entity failed to respond to the other owner(s) in accordance with Requirement R4.

VSL Justifications – PRC-027-1, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R5 is similar in scope to Requirements R1, R2, R3 and R4 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R5 mandates responsible entities address any identified coordination issue(s) prior to implementation. This requirement is similar to Requirement R3 of PRC-023-2 in that it also requires agreement be obtained, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R5 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R5			
Lower	**Moderate**	**High**	**Severe**
			The responsible entity failed to address any identified coordination issue(s), prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) in accordance with Requirement R5.

VSL Justifications – PRC-027-1, R5	
NERC VSL Guidelines	Meets NERC's VSL Guidelines for a Severe VSL—This is a binary or "pass-fail" requirement. The responsible entity either 'addressed' or 'did not address' an identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The responsible entity either 'addressed' or 'did not address' an identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 — Protection System Coordination for Performance During Faults

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1 — Protection System Coordination for Performance During Faults.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

The System Protection Coordination Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures; or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures; nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor and control the Bulk Electric System; or a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System; or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and, therefore, concentrated its approach on the reliability impact of the requirements.

PRC-027-1 Protection System Coordination for Performance During Faults is a new Reliability Standard with the stated purpose: "*To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.*" PRC-027-1 has ~~four (4~~five (5) requirements that incorporate and clarify the reliability intent of Requirements R2 and R3 of PRC-001-2. The new standard addresses the aspects of coordination for new and changes to existing Protection Systems, as well as requiring an initial and periodic review of existing Protection Systems. The new requirements describe the steps necessary to achieve coordination. The coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner, reviewing each others' Protection System settings and schemes, and resolving any identified coordination issues.

All ~~four~~five requirements are assigned VRFs of Medium. The assignment of the Medium VRFs was made based on the premise that failure to perform these coordination activities by themselves would not directly cause or contribute to bulk power system instability, separation, or a Cascading sequence of failures. For a requirement to be assigned a "High" VRF, there should be the expectation that failure to meet the required performance "will" result in instability, separation, or Cascading failures, and this is usually not the case when an applicable entity fails to 'coordinate' activities. While the SDT agrees that, under some circumstances, it is possible that a failure to perform the required activities may hinder the coordination process; however, the failure would not, by itself, result in instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-027-1, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to perform a Protection System Coordination Study for each Interconnect~~ed~~ing Element to verify that Protection Systems components operate in the ~~desired~~intended sequence during Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R1 is similar in scope to Requirements R2, R3, R4 and ~~R4~~R5, as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R1 directs that Protection System Coordination Studies are performed for every Interconnect~~ed~~ing Element to verify coordination of existing Protection Systems. This requirement is similar to Requirement R1 of FAC-002-1, which also requires studies be performed and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to perform a Protection System Coordination Study for each ~~Interconnected Facility~~Interconnecting Element to verify that Protection Systems components operate in the ~~desired~~intended sequence during Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R1 ~~addresses a single objective and has a single VRF.~~does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed a Protection System Coordination Study on an Interconnect~~ed~~ing Element as required in Requirement R1, Part 1.1.1, but was late by less than or equal to 30 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required, but was late by less than or equal to 30 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance with Requirement R1, Part 1.2, but was late by less than or equal to	The responsible entity performed a Protection System Coordination Study on an Interconnect~~ed~~ing Element as required in Requirement R1, Part 1.1.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required, but was late by more than 30 calendar days but less than or equal to 45 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 10 calendar days but less than or	The responsible entity performed a Protection System Coordination Study on an Interconnect~~ed~~ing Element as required in Requirement R1, Part 1.1.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required, but was late by more than 45 calendar days but less than or equal to 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 20 calendar days but less than or	The responsible entity performed a Protection System Coordination Study on an Interconnect~~ed~~ing Element as required in Requirement R1, Part 1.1.1, but was late by more than 90 calendar days. OR The responsible entity performed a Protection System Coordination Study at an interconnecting bus as required in Requirement R1, Parts 1.1.2, 1.1.3, and 1.1.4 or technically justified why a study was not required but was late by more than 60 calendar days. OR The responsible entity provided a summary of the results of each Protection System Coordination Study ~~results~~or a technical justification in accordance with Requirement R1, Part 1.2, but was late by more than 30 calendar

Proposed VSLs for PRC-027-1, R1			
Lower	**Moderate**	**High**	**Severe**
10 calendar days.	equal to 20 calendar days.	equal to 30 calendar days.	days. OR The responsible entity failed to perform a Protection System Coordination Study on an Interconnected Element in accordance with Requirement R1, Parts 1.1.1, 1.1.2, 1.1.3, or 1.1.~~3~~4. OR The responsible entity failed to technically justify why a study was not required in accordance with Requirement R1, Parts 1.1.2, 1.1.3, or 1.1.~~3~~4. OR The responsible entity failed to provide a summary of the results of each Protection System Coordination Study ~~results~~ or a technical justification in accordance with Requirement R1, Part 1.2.

VSL Justifications – PRC-027-1, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to periodically ~~justify why Fault current does not affect the Protection System coordination; or~~ perform a short circuit study~~,~~ to calculate the percent change in Fault current values used as inputs for updating Protection System Coordination Study(s), and to provide ~~each~~the other owner(s) of the Protection System(s) associated with the Interconnect~~ed~~ing Element ~~of requisite changes in~~(s) updated Fault ~~currents~~current values, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R2 is similar in scope to Requirements R1, R3, R4 and ~~R4,~~R5 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R2 facilitates a periodic review of ~~technical justifications or~~ Fault currents, and notification of owner(s) of the Protection System(s) associated with the Interconnect~~ed~~ing Element(s). This requirement is similar to Requirement R6 of BAL-005-0.2b in that it also requires the comparison of calculated data and possible notification of other entities; and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to periodically ~~justify why Fault current does not affect Protection System Coordination; or~~ perform a short circuit study~~,~~ to calculate the percent change in Fault current values used as inputs for updating Protection System Coordination Study(s~~)~~), and to provide ~~each~~the other owner(s) of the Protection System(s) associated with the Interconnect~~ed~~ing Element ~~of requisite deviations in~~(s) updated Fault ~~currents~~current values, if necessary, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System~~,~~ regardless of the situation. ~~Therefore, this Violation Risk Factor level conforms to~~ This requirement meets NERC's ~~definition of~~criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:

	PRC-027-1, Requirement R2 ~~addresses a single objective and has a single VRF.~~does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R2			
Lower	**Moderate**	**High**	**Severe**
~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by less than or equal to 30 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study, as required in Requirement R2, Part 2.1, but was late by less than or equal to 30 calendar days. OR The Transmission Owner provided the owner(s) of the Facility	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 30 calendar days but less than or equal to 60 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 30 calendar days but less than or equal to 60 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 60 calendar days but less than or equal to 90 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 60 calendar days but less than or equal to 90 calendar days. OR The Transmission Owner provided the owner(s) of the Facility associated with the	~~For an Interconnected Element on its System, the Transmission Owner technically justified why Fault current does not affect the Protection System coordination, as required in Requirement R2, but was late by more than 90 calendar days.~~ ~~OR~~ The Transmission Owner performed a short circuit study as required in Requirement R2, Part 2.1, but was late by more than 90 calendar days. OR The Transmission Owner failed to perform a short circuit study, as required in Requirement R2, Part 2.1. OR The Transmission Owner failed to calculate the percent change between the Fault currents, according to the equation designated in Requirement R2, Part 2.2. OR The Transmission Owner provided the owner(s) of the Facility associated with the Interconnect~~ed~~ing Element, the changes in Fault currents, as required in Requirement R2, Part

Proposed VSLs for PRC-027-1, R2			
Lower	**Moderate**	**High**	**Severe**
associated with the Interconnect~~ed~~ing Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by less than or equal to 10 calendar days.	Interconnect~~ed~~ing Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	Interconnect~~ed~~ing Element, the changes in Fault currents, as required in Requirement R2, Part 2.2.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	2.2.1, but was late by more than 30 calendar days. OR The Transmission Owner failed to provide the owner(s) of the Facility associated with the Interconnected Element, the updated Fault current values, as required in Requirement R2, Part 2.2.1.

VSL Justifications – PRC-027-1, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to communicate proposed ~~changes~~change(s) or addition(s) that modify the conditions used in the coordination of Protection ~~Systems~~System(s) associated with an Interconnect~~ed~~ing Element or provide requested information needed to conduct a Protection System Coordination Study could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R3 is similar in scope to Requirements R1, R2, R4 and ~~R4~~R5 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R3 facilitates the provision of pertinent information regarding proposed changes that could impact the coordination of Protection Systems associated with an Interconnect~~ed~~ing Element, or information needed to do a Protection System Coordination Study. This requirement is similar to Requirement ~~R2~~R8 of FAC-~~009-1~~008-3 in that it also requires the provision of reliability data to other pertinent functional entities, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to communicate proposed ~~changes~~change(s) or addition(s) that modify the conditions used in the coordination of Protection ~~Systems~~System(s) associated with an Interconnect~~ed~~ing Element or provide requested information needed to conduct a Protection System Coordination Study could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. ~~Therefore, this Violation Risk Factor level conforms to~~This requirement meets NERC's ~~definition of~~criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R3 ~~addresses a single objective and has a single VRF.~~does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R3			
Lower	**Moderate**	**High**	**Severe**
			The responsible entity failed to provide the owner(s) of the Facility associated with the Interconnect~~ed~~ing Element, details for any proposed change(s) or addition(s) identified in Requirement R3, Part 3.1. OR
The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by less than or equal to 10 calendar days. OR	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 10 calendar days but less than or equal to 20 calendar days. OR	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 20 calendar days but less than or equal to 30 calendar days. OR	The responsible entity provided the requested information required in Requirement R3, Part 3.2, but was late by more than 30 calendar days. OR
The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by less than or equal to 10 calendar days.	The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The responsible entity provided the information required in Requirement R3, Part 3.3, but was late by more than 30 calendar days. OR The responsible entity failed to provide the information required in Requirement R3, Part 3.3.

VSL Justifications – PRC-027-1, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	Failure to ~~communicate~~review a summary of the results of a PSCS or a technical justification and ~~cooperate with~~ respond to the other ~~owners~~owner(s) of the Protection System(s) ~~to resolve coordination issues~~ associated with ~~an Interconnected~~the Interconnecting Element(s) in a timely manner could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R4 is similar in scope to Requirements R1, R2, R3 and ~~R3~~R5 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R4 mandates responsible entities ~~affirm acceptance on~~ review a Protection System Coordination Study ~~results~~summary or a technical justification to determine if there are any issue(s) associated with any proposed ~~changes~~change(s) to the pertinent Protection System(s~~) prior to implementation.~~), and communicate those findings to the sender. This requirement is similar to Requirement ~~R2~~R1 of ~~PRC-023~~FAC-002-1 in that it ~~also~~ requires ~~agreement be obtained~~coordination and cooperation of assessments, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to ~~communicate~~review a summary of the results of a PSCS or a technical justification and ~~cooperate with~~ respond to the other ~~owners~~owner(s) of the Protection System(s) ~~to resolve coordination issues~~ associated with ~~an Interconnected~~the Interconnecting Element(s) in a timely manner could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R4 ~~addresses a single objective and has a single~~

VRF Justifications – PRC-027-1, R4		
		~~VRF.~~does not co-mingle reliability objectives.

Proposed VSLs for PRC-027-1, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity responded in more than 90 calendar days but less than or equal to 100 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1~~.	The responsible entity responded in more than 100 calendar days but less than or equal to 110 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1~~.	The responsible entity responded in more than 110 calendar days but less than or equal to 120 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1~~.	The responsible entity responded in more than 120 calendar days following ~~the~~ receipt of the ~~summary results of the~~ Protection System Coordination Study summary of the results or technical justification, as required in Requirement R4~~, Part 4.1~~. OR The responsible entity failed to review the ~~summary results of the~~ Protection System Coordination Study summary of the results, or the technical justification provided to them in accordance with Requirement R4~~, Part 4.1~~. OR The responsible entity failed to respond to the other ~~owners~~owner(s) in accordance with Requirement R4~~, Part 4.1.~~ ~~OR~~ ~~The responsible entity failed to affirm that the other owner(s) of each Facility associated with the affected Interconnected Element accepted the Protection System(s) changes~~

Proposed VSLs for PRC-027-1, R4			
Lower	**Moderate**	**High**	**Severe**
			~~including the resolution of any identified coordination issues, prior to implementation of those changes, as required in Requirement R4, Part 4.2~~.

VSL Justifications – PRC-027-1, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

VRF Justifications – PRC-027-1, R5	
Proposed VRF	Medium
NERC VRF Discussion	Failure to address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Each requirement in PRC-027-1 is assigned a Medium VRF. Requirement R5 is similar in scope to Requirements R1, R2, R3 and R4 as each requirement details the process steps necessary to achieve coordination.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: PRC-027-1, Requirement R5 mandates responsible entities address any identified coordination issue(s) prior to implementation. This requirement is similar to Requirement R3 of PRC-023-2 in that it also requires agreement be obtained, and is assigned a Medium VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: PRC-027-1, Requirement R5 addresses a single objective and has a single VRF.

Proposed VSLs for PRC-027-1, R5			
Lower	Moderate	High	Severe
			The responsible entity failed to address any identified coordination issue(s), prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s) in accordance with Requirement R5.

VSL Justifications – PRC-027-1, R5	
NERC VSL Guidelines	Meets NERC's VSL Guidelines for a Severe VSL—This is a binary or "pass-fail" requirement. The responsible entity either 'addressed' or 'did not address' an identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new Requirement; consequently, there is no prior level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The responsible entity either 'addressed' or 'did not address' an identified coordination issues prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

NERC
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RELIABILITY CORPORATION

Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Additional Ballot and Non-Binding Poll Now Open through December 18, 2013

Now Available

An additional ballot for **PRC-027-1** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels is now open through **8 p.m. Eastern, Wednesday, December 18, 2013**.

Background information for this project can be found on the project page.

Instructions for Balloting
Members of the ballot pools associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2007-06 System Protection Coordination PRC-027-1

Comment Period: November 4, 2013 – December 18, 2013

Upcoming:
Additional Ballot and Non-Binding Poll for PRC-027-1: December 9-18, 2013

Now Available

A 45-day comment period is open for draft 4 of **PRC-027-1** – Protection System Coordination for Performance During Faults through **8 p.m. Eastern on Wednesday, December 18, 2013**.

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period for **PRC-027-1** is open through **8 p.m. Eastern on Wednesday, December 18, 2013.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot of **PRC-027-1** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted from December 9-18, 2013.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Standards Announcement

Project 2007-06 System Protection Coordination PRC-027-1

Comment Period: November 4, 2013 – December 18, 2013

Upcoming:
Additional Ballot and Non-Binding Poll for PRC-027-1: December 9-18, 2013

Now Available

A 45-day comment period is open for draft 4 of **PRC-027-1** – Protection System Coordination for Performance During Faults through **8 p.m. Eastern on Wednesday, December 18, 2013**.

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period for **PRC-027-1** is open through **8 p.m. Eastern on Wednesday, December 18, 2013.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot of **PRC-027-1** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted from December 9-18, 2013.

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Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot of **PRC-027-1 – System Protection Coordination for Performance During Faults** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Tuesday, December 31, 2013**.

This standard achieved a quorum but did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot	Non-Binding Poll
Quorum /Approval	Quorum/Supportive Opinions
76.60% / 65.71%	76.63% / 70.75%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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-Registered Ballot Body
-Proxy Voters

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Ballot Results	
Ballot Name:	Project 2007-06 Successive Ballot PRC-027-1 December 2012_ad_2
Ballot Period:	12/9/2013 - 12/31/2013
Ballot Type:	
Total # Votes:	311
Total Ballot Pool:	406
Quorum:	76.60 % The Quorum has been reached
Weighted Segment Vote:	65.71 %
Ballot Results:	The Ballot has Closed

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	111	1	51	0.68	24	0.32	2	9	25
2 - Segment 2	9	0.6	3	0.3	3	0.3	0	2	1
3 - Segment 3	97	1	40	0.635	23	0.365	1	6	27
4 - Segment 4	37	1	14	0.56	11	0.44	0	4	8
5 - Segment 5	83	1	35	0.583	25	0.417	0	8	15
6 - Segment 6	50	1	19	0.576	14	0.424	0	4	13
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	5	0.3	2	0.2	1	0.1	0	0	2
9 - Segment 9	6	0.2	2	0.2	0	0	0	0	4

10 - Segment 10	8	0.8	8	0.8	0	0	0	0	0
Totals	**406**	**6.9**	**174**	**4.534**	**101**	**2.366**	**3**	**33**	**95**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Abstain	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Pasadena	Marco A Sustaita		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	City Water, Light & Power of Springfield	Shaun Anders		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Consumers Power Inc.	Stuart Sloan		
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Negative	SUPPORTS THIRD PARTY COMMENTS - ACES
1	El Paso Electric Company	Dennis Malone		
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	COMMENT

				RECEIVED
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca		
1	LG&E Energy Transmission Services	Bradley C. Young		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	John Burnett	Negative	NO COMMENT RECEIVED
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	Metropolitan Water District of Southern California	Ernest Hahn		
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPPD & SPP)
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and NYPA's)
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supporting MRO NSRF comments)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Abstain	
1	PECO Energy	Ronald Schloendorn	Negative	COMMENT RECEIVED
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	COMMENT RECEIVED
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted for PPL NERC Registered Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
				SUPPORTS

1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	THIRD PARTY COMMENTS - (Comments of Public Service Enterprise Group)
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Negative	NO COMMENT RECEIVED - (Small Entity Group)
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Negative	COMMENT RECEIVED
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry G Akens	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	Turlock Irrigation District	Esteban Martinez		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Denike		
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Abstain	
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	

2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Alameda Municipal Power	Douglas Draeger		
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pepco Holdings Inc & Affiliates)
3	Basin Electric Power Cooperative	Daniel Klempel		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Bonneville Power Administration	Rebecca Berdahl	Negative	COMMENT RECEIVED
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Lodi, California	Elizabeth Kirkley		
3	City of Palo Alto	Eric R Scott		
3	City of Redding	Bill Hughes	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
3	City of Ukiah	Colin Murphey		
3	City Water, Light & Power of Springfield	Roger Powers		
3	Clearwater Power Co.	Dave Hagen		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	COMMENT RECEIVED
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Consumers Power Inc.	Roman Gillen		
3	Coos-Curry Electric Cooperative, Inc	Roger Meader		
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pepco Holdings Inc & Affiliates)
3	Detroit Edison Company	Kent Kujala	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger	Abstain	
3	Fall River Rural Electric Cooperative	Bryan Case		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Russ Schneider)
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover		
3	Hydro One Networks, Inc.	David Kiguel	Negative	COMMENT RECEIVED
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		

3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lane Electric Cooperative, Inc.	Rick Crinklaw		
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Negative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments from PPL NERC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS: supports the comments of the MRO NSRF
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Nebraska Public Power District comments)
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support comments being submitted by Saul Rojas of NYPA)
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Northern Lights Inc.	Jon Shelby		
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS. OPPD is supporting MRO NSRF comments.
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Pacific Northwest Generating Cooperative	Rick Paschall		
3	PacifiCorp	Dan Zollner	Abstain	
3	Pepco Holdings, Inc.	Mark R Jones	Negative	COMMENT RECEIVED
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Negative	COMMENT RECEIVED
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)

3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Raft River Rural Electric Cooperative	Heber Carpenter		
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salmon River Electric Cooperative	Ken Dizes	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments will be submitted by Chang Choi.)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Umatilla Electric Cooperative	Steve Eldrige		
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barbara Kedrowski)
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy Comments)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Abstain	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	COMMENT RECEIVED
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
				SUPPORTS THIRD PARTY

4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	COMMENTS - (MRO NSRF comments)
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Pacific Northwest Generating Cooperative	Aleka K Scott		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative (Bret Galbraith) comments)
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Southern Minnesota Municipal Power Agency	Richard L Koch		
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	COMMENT RECEIVED
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski, We Energies)
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Abstain	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	

5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst		
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Michael Korchynsky	Negative	COMMENT RECEIVED
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh		
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero		
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF SRT)
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	Muscatine Power & Water	Mike Avesing	Abstain	
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and NYPA's comments)
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF Standards Review Team)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC

				Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support the NAGF comments)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase, Seattle City Light)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Galbraith for Seminole Electric Cooperative Inc.)
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
5	Tampa Electric Co.	RJames Rocha	Negative	COMMENT RECEIVED - (Ron Donahey comments)
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Westar Energy	Bryan Taggart	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barbara Kedrowski)
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland)
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Abstain	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	

6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil		
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brad Jones		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYPA and NPCC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting comments on behalf of SEminole Electric Cooperative, Inc)
				SUPPORTS

6	Snohomish County PUD No. 1	William T Moojen	Negative	THIRD PARTY COMMENTS: Sacramento Municipal Utility District
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	COMMENT RECEIVED
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner		
8		Edward C Stein		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
9	California Energy Commission	William M Chamberlain		
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	Oregon Public Utility Commission	Jerome Murray		
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Non-Binding Poll Results

Project 2007-06: PRC-027-1

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2007-06 Non-binding Poll PRC-027-1
Poll Period:	12/9/2013 - 12/31/2013
Total # Opinions:	288
Total Ballot Pool:	371
Ballot Results:	77.63% of those who registered to participate provided an opinion or an abstention; 70.75% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Abstain	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Pasadena	Marco A Sustaita		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	City Water, Light & Power of Springfield	Shaun Anders		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	

1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Negative	SUPPORTS THIRD PARTY COMMENTS - ACES
1	El Paso Electric Company	Dennis Malone		
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	NO COMMENT RECEIVED
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca		
1	LG&E Energy Transmission Services	Bradley C. Young		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	John Burnett	Negative	NO COMMENT RECEIVED
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)

1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and NYPA's)
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber		
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supporting MRO NSRF comments)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Abstain	
1	PECO Energy	Ronald Schloendorn	Negative	COMMENT RECEIVED
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted for PPL NERC Registered Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Negative	NO COMMENT RECEIVED - (Small Entity Group)
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	

1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
1	South California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	Turlock Irrigation District	Esteban Martinez		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Denike		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Alameda Municipal Power	Douglas Draeger		
3	Ameren Services	Mark Peters	Abstain	

3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Basin Electric Power Cooperative	Daniel Klempel		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Lodi, California	Elizabeth Kirkley		
3	City of Palo Alto	Eric R Scott		
3	City of Redding	Bill Hughes	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
3	City of Ukiah	Colin Murphey		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	COMMENT RECEIVED
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Abstain	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Russ Schneider)
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover		
3	Hydro One Networks, Inc.	David Kiguel	Negative	COMMENT RECEIVED
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Negative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		

3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS of the MRO NSRF
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support comments being submitted by Saul Rojas of NYPA)
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS. OPPD is supporting MRO NSRF comments.
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salmon River Electric Cooperative	Ken Dizes	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)

3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments will be submitted by Chang Choi.)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP STandards Group)
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Abstain	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF comments)
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	

NERC

4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative (Bret Galbraith))
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski, We Energies)
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Edward Cambridge	Abstain	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (SCL comment)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Phillip Porter		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (SMUD)
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst		
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens		
5	Detroit Edison Company	Christy Wicke	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Michael Korchynsky	Negative	COMMENT RECEIVED
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh		
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF SRT)
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	Muscatine Power & Water	Mike Avesing	Abstain	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and NYPAs comments)

5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF Standards Review Team)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support the NAGF comments)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase, Seattle City Light)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Michael Haff for Seminole Electric Cooperative Inc.)
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Sacramento Municipal Utility District)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
5	Tampa Electric Co.	RJames Rocha	Negative	COMMENT RECEIVED - (Ron Donahey comments)
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn		
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Abstain	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Duke Energy	Greg Cecil		
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	

6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brad Jones		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYPA and NPCC)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	John Jamieson		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting comments on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	William T Moojen	Negative	SUPPORTS THIRD PARTY COMMENTS of Sacramento Municipal Utility District
6	South California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	

6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Edward C Stein		
8		James A Maenner		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
9	California Energy Commission	William M Chamberlain		
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (47 Responses)
Name (27 Responses)
Organization (27 Responses)
Group Name (20 Responses)
Lead Contact (20 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (1 Responses)
Comments (47 Responses)
Question 1 (0 Responses)
Question 1 Comments (46 Responses)

Group
MRO NSRF
Russel Mountjoy
In the rationale for Requirement R1 Part 1.1.1, the SPCSDT acknowledges that "...The drafting team has no evidence there is widespread mis-coordination of Protection Systems associated with Interconnecting Elements that warrants a shorter time frame." We suggest, using the same aforementioned rationale, if there is no widespread mis-coordination, then, why create a mandatory requirement. As currently drafted, the drafting team would place excessive documentation requirements on registered entities for activities already being performed as industry best practices. Per R3, The NSRF recommends to rewrite and update R3 to read: Each TO, GO and DP should provide "when requested" by each TO, GO or DP... As written if an entity misses one piece of information then there we be a required self-report. The fact of pushing information is not a Reliability issue. The applicable entity should pass information when requested to by the asking entity.
Individual
Thomas Foltz
American Electric Power
We believe the usage of the term "interconnecting bus" within figures 1 through 5 unintentionally causes confusion in identifying the Interconnecting Element. We suggest removing interconnecting bus from the illustrations, and instead, use color coding to clearly indicate the Interconnecting Element. We suggest adding a sentence at the beginning of Figure 5, similar to the other figures, which verbally describes the Interconnecting Element in that particular example.
Individual
Brenda Frazer
Edison Mission Marketing & Trading Inc.
The requirement for all our NERC sites to perform a Protection System Coordination Study will be an expensive and burdensome effort. We have funded internconnection and system impact studies already. This effort, if critical to the BES is best undertaken by the TO, who has a wider purview of the BES. This standard has the potential to include studies at all of our Wind sites, because the Transmission Owners will be required to perform studies at the interconnecting substations. In the rationale for R1 Part 1.1.1, the drafting team states, "The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnecting Elements that warrants a shorter time frame". The time frame to conclude the study is 60 months. If there is no issues now, why perform a study that is due in 5 years? What value is that? This is a poorly organized standard revision, constantly referring to requirements later in in the standard. It makes for a difficult read.
Individual
Ayesha Sabouba

Hydro One
Agree
TFSP
Individual
Silvia Parada Micthell
NextEra Energy
R3.1. Bullets 2 , 3 and 4. Concerned that these state “changes …. that alter any sequence component…”. NextEra Energy recommends this be revised to state “changes…..that significantly alter any sequence component….” The current wording would allow an auditor to ask if we even insignificant changes such as a few inches on a jumper on a 10 mile transmission line. With the work “significantly” added, TOs can define a change that triggers a review as when it would have an effect on relaying.
Group
Northeast Power Corodinating Council
Guy Zito
The Purpose statement “To coordinate Protection Systems for Interconnecting Elements such that Protection System components operate in the intended sequence during Faults” is confusing. Are the protection systems involved specifically for the Interconnecting Element, or between Facilities connected by an Interconnecting Element? It also inappropriate because the standard does not address Protection System coordination among operating entities. According to the NERC White Paper “Power Plant and Transmission System Protection Coordination”, stator ground protection may need to be coordinated with transmission system faults. Stator ground is a generator protection – so is that in scope of the PSCS specified in the standard since this protection is a generator protection, not an Interconnecting Element protection? For Part 3.1, it is not clear what is meant by “Details….. associated with the Interconnecting Element or at other Facilities…..” What is the burden of proof associated with this requirement? In the long term planning horizon, is it implied this assessment be made through short circuit studies? It would be proper to associate Part 3.1 solely with changes/additions “either at an existing or new Facility associated with the Interconnecting Element….”. Changes at other Facilities could mean 1, 2 or 3 busses away and we believe if these changes were significant, they would manifest themselves in a significant change in Fault current levels. Furthermore, in an audit, the burden of proof lies with the owner to show these changes “at other Facilities” don’t affect coordination. Suggest the following change to the wording: “Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s) where such changes result in a change of 10% or greater in either single line-to-ground or three-phase fault current as defined in R2.2.” The Process Flow chart in the Applications Guidelines of the standard needs to be revised to reflect the revisions in the standard.
Group
Pepco Holdings Inc. & Affiliates
David Thorne
1) A word search of the Final Report on the August 14, 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. The mention of the appropriate use of time delays in relays in the 2003 Blackout Report was in the context of the actuating time of relays in response to system overload conditions, and generator protection to voltage and frequency excursions during stressed system conditions. The concern was that relays operated on overload before system operators could react and that some generators tripped (exacerbating the collapse) before other system schemes (UFLS or UVLS) could operate. The solution was not to increase the time delay on Zone 3 relays (which would have been intolerable for fault clearing purposes) but to address the relay loadability issue in PRC-023, to make them immune from operating under heavy load conditions. Similarly the premature tripping of generators on

voltage and frequency protection during stressed system conditions (not fault conditions) and coordination with system UFLS and UVLS schemes was discussed in the report. Likewise those issues have now been addressed, or are being addressed, in PRC-006, PRC-010, PRC-022, PRC-019, and PRC-024. Similarly in the recent Southwest Blackout of 2011 the operation of relay schemes during overload conditions was a contributing factor. There was again no evidence of miscoordination of relay schemes during fault conditions. The unexpected operation of relays and SPS's during overload conditions could have been avoided by proper application of existing standards PRC-023 and PRC-014-0. Based on the above, where is the historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions? Reliability Standards should be adopted based on a need to address a known, or probable, reliability issue. As such, although PHI supports the overall desire to ensure that protective systems are properly coordinated; PHI sees little value in developing a new Reliability Standard to address something that is routinely practiced and which has not been demonstrated to be a contributor to major system disturbances, or cascading outages. Even the SDT in their rationale for Requirement R1.1.1 stated that they have no evidence that there is widespread miscoordination between Interconnected Facilities. In lieu of a formal standard to address relay coordination during faults, a simple technical reference document on Protective System Coordination issues may provide equal benefit to the industry. The above comment was also submitted with previous drafts of this standard. In previous responses the SDT stated that PRC-027 was being developed in response to FERC Order 693. However, Order 693 only directs NERC to address specific deficiencies in PRC-001 surrounding certain measures and levels of non-compliance relating to the notification and response to the detection of failures in relay protection systems. As such, PHI believes PRC-027 goes well beyond what is was directed by FERC, and the stated purpose of the SAR. PHI urges the SDT to revisit FERC Order 693 and revise this standard as appropriate to address only the stated FERC directives. 2) Based on the arguments presented in the above comments, including the lack of historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions, PHI suggests that NERC conduct a Cost Effective Analysis (CEA) to provide information about cost impacts (e.g., implementation and ongoing compliance resource requirements) of this draft standard and its relative effectiveness in preventing widespread blackouts, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of this standard. 3) PHI finds that splitting Requirement R4 into two requirements (R4 & R5) does little to address the root problem associated with mandating mutual agreement, which essentially R5 requires, since any setting changes cannot be implemented until both parties agree that all identified coordination issues have been addressed. PHI suggests Requirement R5 be removed entirely or extensively re-written to address the concerns outlined below: Requirement R5 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What if agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R5 until agreement is reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? This is the problem with mandating that an agreement between two parties be reached. It is further compounded by requiring that an agreement be reached within a set timeframe. It is unreasonable and unfair to hold one party non-compliant due to the failure of

another party to reach agreement. Furthermore, in the example provided above, it is a detriment to reliability to delay implementation of the setting change on breaker D just because mutual agreement could not be reached. It is important to ensure that information on new, or modified, Protection Systems are shared between parties, so that each party may assess the impact of the change and ensure their Protection Systems are properly set and coordinated. The emphasis should be on sharing of information (such as relay setting changes) and not the details of performing the "Protection System Study" and all the associated approval schedules. As such, it may be reasonable to have a Reliability Standard to ensure setting information has been exchanged (which was the original intent of the PRC-001-1 standard). But it should be left at that. Mandating mutual agreement with compliance implications, without providing a clear division of responsibilities and assignment of who will be held non-compliant if agreement cannot be reached is unfair to either party. 4) For the case where one registered entity represents multiple Functional Entities and the same protection group performs all the coordination, the drafting team included the following note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities. However, this reference is only included in the Rationale boxes and the Guidelines and Technical Basis sections and not in the associated Requirements and Measures. The Measures themselves for Requirements R3 and R4 are very specific that acceptable evidence must include dated documentation that the information was supplied/exchanged between Functional Entities. What constitutes acceptable evidence to satisfy R3 & R4 if a single protection group, which is responsible for all protection coordination for both TO and DP functions within the same company, performs all the coordination for both groups? Does the PSCS have to specifically mention that the PSCS was performed by a single protection group on behalf of both Functional Entities? Or, does there need to be dated evidence that some representative from each Functional Entity has reviewed the information and signed off on it? A specific clarification on this point in needed within the wording of the Measures themselves and not just in the Rationale box.
Individual
Kayleigh Wilkerson
Lincoln Electric System
Although appreciative of the drafting team's efforts in developing PRC-027-1, LES does not believe that there will be an improvement to BES reliability that justifies the cost and effort involved in compliance with this new standard. In its response to LES' previous comments, the drafting team contended that PRC-027-1 was necessary "to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES." Although LES believes PRC-001 would still be adequate for this purpose, at a minimum, the replacement for PRC-001 should be a standard that is much less prescriptive and one that, to a greater degree, acknowledges the necessity of engineering judgment than does the current draft of PRC-027. As an example, R3 requires that functional entities provide details of a proposed change to the other interconnected entities when the change modifies the conditions used in the coordination of Protection Systems. In this instance, it is obvious that some engineering judgment must be exercised in determining if a small change actually modifies the conditions used in coordination. Does the drafting team contend that this determination can be made by one entity or must there be consensus between the interconnected entities? A less prescriptive standard would avoid the compliance questions raised by a situation such as this and allow entities to continue the commonsense approach to coordination that they have taken in the past.
Group
North American Generator Forum - Standard Review Team (NAGF-SRT)
Allen Schriver
Comments: The statement was made in the 12/5/13 webinar that PRC-027-1 requires nothing more in the way of GO-TO information exchanges than what is already mandated in PRC-001, but PRC-001 requires just that TOs "coordinate" their changes with others while PRC-027-1 makes GOs perform a Protection System Coordination Study (PSCS) for TO changes or provide a technical justification as to why a PSCS is not required. The only inputs that GOs need from TOs are the fault current at interconnecting buses (affects the GO's arc-flash studies) and the grid X/R ratio, so PRC-

001 coordination for TO changes would typically consist for GOs of just obtaining these two values, not requesting and analyzing the detailed TO information cited on p.23 of PRC-027-1 (“power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings”). There remains the technical issue that TO changes do not affect GOs’ Protection System configurations or settings. That is, making GOs perform PSCSs would serve no useful purpose, especially since everything involving tripping elements in the intended sequence (the stated purpose of PRC-027-1) is in the TO’s system. GOs should consequently have no Protection System coordination duties other reporting planned changes prior to implementation and receiving the two inputs cited above, per PRC-001. The following issues and corresponding proposed solutions are offered for consideration of the SDT: 1) Issue: We believe that there exist too many time frame measurements (14) in total for this standard. The burden of tracking these time frames for each interconnection is excessively onerous. The time frames noted in the draft standard are listed here to demonstrate the extent of the problem. The time frames identified are: • 60 months post effective date of the standard, have a PSCS for each IE (R1.1.1) • 12 months post If change > 10%, have a PSCS for IE (R1.1.2) • On an agreed upon time frame (variable) – schedule, have a PSCS for IE (proposed changes) – (R1.1.3) • 6 month post notice of “other” emergency equipment change, PSCS for IE (R1.1.4) • 60 months (recurring), TO calc If (new), % change, communicate (R.2.1, R2.2) • 30 days post ID If(new) change > 10%, notify others (R2.2.1) • Before coordination change/addition, notify others (R3.1) • 30 days post request for info, provide info (R3.2) • On an agreed upon schedule (variable) post request for info, provide info (R3.2) • 30 post change (misop. Investigation, maint., emergency replacement), notify others (R3.3) • 90 days post PSCS finished, provide to others (R1.2) • 90 days post receipt of PSCS, confirm review and state of issues (R4) • On agreed upon schedule post receipt of PSCSS, confirm review and state of issues. (R4) • Before change/addition, address any R4 issues (R5) 1A) Proposed Solution: The drafting team should strive to eliminate any and all that are not absolutely necessary. Perhaps more usage of “mutually agreed upon time frames” could relieve the burden. 2) Issue - Multiple measure #’s used for each Requirement number. 2A) Proposed Solution – Either one of the following: a) separate the multiple requirements embedded within each major Requirement number so that the requirement number and measure number’s match for each requirement, or b) group the various measures listed for each main Requirement number in a single measure. Non-matching numbers for the requirements & measures is confusing. 3) Issue - R3 should state what is to be provided. 3A) Proposed Solution – Add “the following information” after “provide” in the 1st line of R3. 4) Issue - R3.1 is confusing because of the use of “either” and two instances of “or” which follow. Also, no colon introduces the bulleted text. 4A) Proposed Solution – Modify R3.1 to the following: “Details for any proposed change or addition listed below [at existing / new Facilities associated with the Interconnecting Element or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s)]: 5) Issue - An auditor may argue that for the changes referenced in R3.3 an entity proposes to initiate (to change or add replacement equipment), at some instant in time has a plan and intends to make the change, and therefore is subject to R3.1 (and should have notified others prior to the change or addition). 5A) Proposed Solution – In order to prevent potential confusion, would the SDT consider modifying R4 & R5 to include exclusions for a PSCS performed as a result of “other changes” specified in R3.3. 6) Issue - R3.3 wording needs improvement. A reader is looking for what information must be provided as they goes from R3 to 3.1, 3.2, and 3.3. Beginning 3.3 with “Within 30…” makes it difficult to determine what is to be provided. 6A) Proposed Solution – Move “within 30…” to the end of the sentence so that it is immediately evident that the entity shall provide “details of permanent changes…” 7) Issue - The short circuit (R2.2.1) section of the process flow chart in the Application Guidelines section is short circuited. 7A) Proposed Solution –Remove short circuit in the diagram.
Individual
Brett Holland
Kansas City Power & Light
What makes the internal lines of a single Registered Transmission Owner any different than a Registered Entity that represents multiple functional entity responsibilities, i.e. Generator Owner, Transmission Owner, and Distribution Provider, where one single group performs the overall coordination study? We propose the following change under the Definitions of Terms Used in

Standard - Interconnecting Element part b) should be changed to read: b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Transmission Owner, Generator Owner, or Distribution Provider) where no one single group performs the overall coordination study for the given Interconnecting Element. This change to the standard does not affect the purpose of the standard, which is to provide coordination. Our proposed change clarifies that where one single System Protection group is performing the coordination that is required, then the communication will take place within the System Protection group and will be accomplished exactly the same way as it would be for internal lines of a single Registered Transmission Owner. - NEXT – We completely agree with the purpose of the standard; to coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the intended sequence during faults. We believe that the standard needs to take into account the differences between Owners that use communication assisted schemes and those that do not. We believe that the 60 month fault study requirement should not be required for utilities that do not use instantaneous overcurrents or time overcurrents that are always slower than zone 2 time. We propose the following change to R2; R2. For each Interconnecting Element on its System, the Transmission Owner shall technically justify why Fault current does not affect the Protection Coordination, or once every 60 months: If you should choose to accept our proposed change to R2, then the removal of the technical justifications from Requirement R2 in the Application Guidelines cannot be made. It is not true that all primary and backup protection is equal. Note the contrast in the following examples. In a scheme that employs only step distance and overcurrents, Zone 2 would be the primary trip for a fault near the remote end, and the overcurrents or Zone 3 would be the backup. In a scheme that employs communication assisted tripping the piloted scheme would be the primary trip, Zone 2 would be the backup, and the overcurrents or Zone 3 may act as the second layer of backup. The chances of needing the second layer of backup are extremely low. In a scheme that employs two forms of communication assisted schemes, one piloted scheme would be the primary trip, one piloted scheme would be the backup, Zone 2 would be the second layer of backup, and the overcurrents or Zone 3 would be the third layer of backup. The chances of needing the second or third layer of backup are extremely low. Note that during the Webinar on December 5, 2013 the statement below was made that reinforces the fact that R2 for Transmission Owners interacting with Generator Owners is unnecessary if it can be shown that system fault current does not affect the coordination provided. …. "particularly in generation sites, the majority of Fault current being contributed is coming from the generator and it is going to be rare unless you add a generator or retire a generator that the fault current evaluation done by the Transmission Owner at that bus is ever going to change by more than that 10% ……. by using a fault current trigger it may indeed be that they never have to be reviewed." Why should a Transmission Owner be required to periodically perform a short circuit study at a generator bus when the fault contributed by the generator will never change by 10% unless a unit is retired, modified, or added? Requirement R2 specifies a 10% change in fault current as the trigger for a review of the Protection Coordination. We believe that the only time that a Protection Coordination Study should be triggered is if the fault current increases by more than 10%. Since Fault studies are conducted with all generation on, the Fault current calculated by the short circuit study will be greater than the Fault current under most conditions, because all generation is rarely on. Therefore reductions in fault current are relative and a 10% decrease could be the Fault current that the system typically operates at. We propose the following change to 2.2.1; 2.2.1 Within 30 calendar days after identification of an increase of 10% or greater in either single line to ground of 3-phase Fault current, provide the updated Fault current values (Iscs) to each owner of the Protection Systems(s) associated with the Interconnecting Element(s). Due to the reasons presented above we do not agree with the changes made in the Application Guidelines associated to Requirement R2 or the Process Flow Chart portion that map Requirement R2.
Group
Tacoma Power
Chang G. Choi
On the last page of the Implementation Plan, change "…twelve (12) months after the date that the PRC-001-3 is…" to "…twelve (12) months after the date that PRC-001-3 is…" In the proposed definition of 'Interconnecting Element', the verbiage "owned by the same Registered Entity that represents multiple functional entity responsibilities" poses at least two challenges. First, it seems to

suggest that any BES Element owned by that entity would be an Interconnecting Element. It is believed that this is not the intent of the definition. Consider language like one of the following instead: “owned by the same Registered Entity that represents multiple functional entity responsibilities where more than one of these functional entities are responsible for the electrically joined Facilities” or “owned by the same Registered Entity but represented by multiple functional entity responsibilities.” Second, an additional challenge for Registered Entities that represent multiple functional entity responsibilities may be identifying which Element(s) is/are the Interconnecting Element(s). For example, are transmission Facilities near generation Facilities associated with the Generator Owner function or the Transmission Owner function? Similarly, are transmission Facilities near distribution Facilities associated with the Distribution Provider function or the Transmission Owner function? In these cases, the Registered Entity should be afforded some latitude in defining the Interconnecting Element(s). For example, referring to Figure 3 in the Application Guidelines, assume that there is one owner for all of the equipment represented. Further assume that the Registered Entity considers the Protection System, installed for the purpose of detecting Faults on BES Elements, at Breaker C to be associated with its Transmission Owner function. Then, it appears that there would be no Interconnecting Element in this scenario, according to the proposed definition of an Interconnecting Element. On the other hand, assume that the Registered Entity considers the Protection System, installed for the purpose of detecting Faults on BES Elements, at Breaker C to be associated with its Distribution Provide function. Then, it appears that there would be an Interconnecting Element in this scenario, according to the proposed definition of an Interconnecting Element. It might help to have one or more examples in the Application Guidelines of how part (b) of the proposed definition of an Interconnecting Element would be applied. In the Purpose, remove ‘components’. It should be sufficient to simply state that the purpose is “[t]o coordinate Protection Systems for Interconnecting Elements, such that Protection Systems operate in the intended sequence during Faults.” This purpose statement is also more consistent with the proposed definition of a Protection System Coordination Study. After a PSCS for an Interconnecting Element is developed and is accepted and implemented by all applicable entities, if a mis-operation associated with the Interconnecting Element occurs that is attributed to mis-coordination of one or more of the Protection Systems addressed by the PSCS, would this automatically be considered a violation of PRC-027-1? Under Applicability, change “Distribution Provider (that own…” to “Distribution Provider (that owns…” Consideration should be given to including the following language, presently included in the Rationale for R1, in the body of the standard itself: “In cases where a single group performs an overall coordination study for a given Interconnecting Element, a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities.” Similarly, consideration should be given to including the following language, presently included in the Rationales for R3 and R4, in the body of the standard itself: “In cases where a single group performs an overall coordination study for a given Interconnecting Element, a single document that describes the information listed in Requirement R3, Parts 3.1 and 3.3 below is sufficient for use by all entities.” In general, how would these exceptions impact an entity’s demonstration of compliance with Requirement R5? In Requirement R1, Part 1.2, the verbiage “…the associated Fault current(s)…” is ambiguous without additional guidance. Should this phrase be interpreted as “[a] listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Facility under study,” as stated in the Application Guidelines? If so, what would be an example of Fault currents for an Element, as opposed to a bus? In Requirement R1, Part 1.2, should “the contingencies used in the evaluation” be itemized as being required in the summary of the PSCS? This is mentioned in the Application Guidelines but not in the standard itself. Referring to Requirement R2, what if modeling errors are identified after a short circuit study is conducted? Is this an automatic violation of Requirement R2? In Measurement M4, change “…each owner of the Protection System…” to “…each owner of the Protection Systems…” or “…each owner of the Protection System(s)…” In Requirement R3, Part 3.1, the language “…or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s)” is ambiguous. What might be helpful is one or more examples (possibly within the Application Guidelines) of changes at other Facilities that would not require action pursuant to Requirement R3, Part 3.1. As the standard is written now, it would be easy to interpret that any change at any BES Facility would likely require action pursuant to Requirement R3, Part 3.1. It is not believed that this is the intent of the requirement. If it is the intent, then there would be no need to run short circuit studies at least every 60 calendar months because all changes impacting short circuit current at interconnecting

buses would already be addressed. In Requirement R3, Part 3.3, please confirm that the clause "…made due to failures of Protection System components" applies only to emergency replacements, and not necessarily to Misoperation investigations, commissioning, or maintenance activities. Consider two entities, Entity A and Entity B. Entity A submits a summary of a PSCS to Entity B pursuant to Requirement R1. Entity B then must respond pursuant to Requirement R4. As written, Requirement R5 appears only to require that Entity A address any identified coordination issues prior to implementation. However, Entity A may have identified issues associated with Entity B. It does not appear that the standard requires Entity B to take any action to address issues identified by Entity A. Provided this is a correct interpretation of the standard, would Entity A be permitted to implement the "proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s)" if Entity B elects not to address the issues identified initially by Entity A? On the other hand, if it is an incorrect interpretation of the standard, then additional clarification may be required. In the Application Guidelines, change "Examples of Protection Systems where technical justifications may be used include:" to "Examples of Protection Systems where technical justifications may be used include, but are not necessarily limited to:" In the Application Guidelines, under "Examples of Protection Systems where technical justifications may be used include," consider including "local breaker failure schemes" as a bullet under "Supervised overcurrent elements enabled by:" In the Application Guidelines, under "Examples of Protection Systems where technical justifications may be used include," consider changing "(i.e. transformer overcurrent, reverse power, etc.)" to "(i.e., transformer overcurrent, reverse power, generator phase-balance current, etc.)."
Individual
Michelle R DAntuono
Ingleside Cogeneration LP
Although we agree with the technical and logistical requirements incorporated into PRC-027-1, Ingleside Cogeneration still believes that an initial baseline of every interconnection is not necessary. We understand that older Fault studies may meet the intent of a Protection System Coordination Study, but believe where a PSCS does not exist; that commissioning and/or major upgrade testing records are sufficient. An extensive battery of studies and validations take place during these initiatives – and it is a reasonable assumption that the Protection System Fault sequencing was confirmed as well. If there was extensive evidence that Fault coordination was a major contributor to BES-level Disturbances, the effort to re-verify each Interconnecting Element may be justified. However, this evidence is not compelling – and the resources needed to support this effort can be applied to more pressing needs in our view. Should the TO find that the maximum Fault current has increased by 10% or more since their previous study, Ingleside will be prepared to engage in a coordinated follow-up review. The same is true if we or the Transmission Owner make a material change on either side of the Interconnected Element. Otherwise, we believe that the baseline effort serves only to satisfy an administrative purpose that makes little or any improvement in BES reliability.
Group
Nebraska Public Power District (NPPD)
Cole Brodine
Requirement R5 requires an entity "that received a response pursuant to Requirement R4 shall address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s)". In M9 it is stated that "Acceptable evidence for Requirement R5 is dated documentation (hardcopy or electronic fileformats) demonstrating that a response pursuant to Requirement R4 was received". It would be recommended that M9 instead read "demonstrating that IF a response pursuant to Requirement R4 was received…" since receiving a response in a timely or untimely manner is not in the control of the requestor so they should not be held accountable. R2 2.2.1 states "Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (Iscs) to each owner of the Protection System(s) associated with the Interconnecting Element(s)." This 30 day timeline seems too tight compared to its relationship with a 5 year study plan that will involve interface and model discussions with other entities. I recommend this timeline be changed to match the Requirement 1 R1.1.2 with a 12 month

timeline instead of 30 days. Rationale for R3 states “The drafting team contends that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated.” I agree this statement is true. In light of this it would appear that 30 days for 3.2 and 3.3 seems too short. The Part 1.1.1 application guidelines also state: “Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” I believe it is reasonable not to implement additional standard requirements if data does not support it. Note that draft PRC-004-3 has provisions for entities to interface for misoperations so it would be reasonable to evaluate those timelines or eliminate misoperation references altogether from PRC-027 to avoid confusion. In addition R3.3 requires time lines for “emergency replacements” which do not seem realistic since these can be times of great flux. If PRC-004 has longer timelines it seems odd it is so tight in PRC-027. I recommend R3.3 be removed. At a minimum consider changing the time line such as R3 3.2 and if 3.3 from 30 and 90 days to match R4. This will help to minimize the numerous time lines.
Group
IRC Standards Review Committee
Charles Yeung
We have commented several times in the PRC standards proposals, that the requirements in PRC-001 having been retired, must be resolved. Since this has been dismissed as out of scope for the SDT, we ask the SDT to bring this issue to the Standards Committee to be addressed. NERC should develop a protocol to pass issues raised in standards development which may be out of scope of a SDT to be addressed formally by the Standards Committee. The Standards Committee should either respond to the commenter through the standards process available avenues, or provide a response directly to the commenter(s). We again urge the PRC SDT to work with staff and the PER SDT to submit an addendum SAR or a revised SAR to the SC for its approval to post for industry comment, then proceed to retire PRC-001-2 R1 by mapping it into an appropriate PER standard. Further delay in addressing the issue until a new project is initiated may result in dragging the approval of PRC-027-1 for another several months to a year.
Individual
David Jendras
Ameren
On page 22 of the Application Guide item 1, replace ‘bus or’ with ‘Interconnecting’ to clarify by using the defined term Interconnecting Element. This yields: ‘A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the Interconnecting Element at the Facility, and which were reviewed for coordination of protective relays as part of the study, including the contingencies used in the evaluation.’
Individual
Michael Falvo
Independent Electricity System Operator
As indicated in a number of our previous comments, we continue to disagree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded or be mapped into another standard. The above view is consistent with the Independent Experts Review Panel’s recommendation. The SDT’s view that the retirement of PRC-001-2 Requirement R1 is outside the scope of this project and the scope of Project 2010-01 (Training) does not provide a satisfactory solution to this issue. In our view, the SDT of either this project or of Project 2010-01 should have submit an addendum or revised SAR to the Standards Committee for approval to post for industry comment, then revise the appropriate PER standard accordingly. We offered the above comment about a year ago. Had an addendum SAR or a revised SAR been posted then, the PRC-001-2 R1 issue would have been fully addressed by now. We are disappointed that over this period, neither NERC staff nor the PRC-027 SDT took the proactive action to proactively address/close out the issue. Today, we still have a requirement that is improper or does not have a proper home. Once again, we urge NERC staff and the SDT to act now

to post an addendum SAR or a revised SAR to fully resolve this issue. Further delay in addressing the issue until a new project is initiated may result in dragging the approval of PRC-027-1 for another several months to a year.
Group
NYPA
Saul Rojas
The issue with PRC-027-1 revolves around the applicability of this Standard. In New York State, the NYISO (BA, RC, TOP, and TP) conducts semiannual short circuit studies after soliciting and incorporating additions, corrections, and comments from its member entities (Requirement 2). In addition, whenever an entity or outside developer wishes to add generation or transmission to the NYISO control area, the NYISO conducts the official studies, indicating any changes to circuit breaker duties as a result of such addition(s). These indications also go below a 10% threshold (Requirement 2). Lastly, though the technical validation of new or modified Protection Systems is performed by the TOs, GOs and DPs, in NYS the NYISO is involved from an oversight point of view (Requirement 3) – they require this data submitted to them so they can update the dynamic and steady state models – MOD-010 and MOD-011 – possible overlap of regulation.
Individual
Shirley Mayadewi
Manitoba Hydro
(1) R1, 1.1.3 - the opening of this part would be clearer if reworded to say 'Within an agreed upon time frame if notified....' Reference to 'change' should be to a ''proposed change or addition' to to be consistent. (2) R1, 1.1.4 - reference to 'change' should be to a 'permanent change' to be consistent. (3) R1, 1.2 - would be clearer if reworded to insert a (i) after the colon and a (ii) after 'or'. (4) M1 - would be clearer if reworded to insert a (i) before 'a dated PCSC' and insert 'or (ii) if relying on a technical justification' after achieved and in place of 'acceptable evidence of a technical justification'. (5) R2, 2.1 and 2.2 - bus(s) should be bus(es). (6) M3 - reference to 'present Fault current values' should be 'present maximum available Fault current values' to be consistent and reference to 'the equation' should be to 'the equation in Part 2.2'. (7) R3, 3.2 - the timeframe (within 30 calendar days of ..... schedule) at the beginning of the sentence would make the wording of this part more consistent with the rest of the drafting. (8) R3, 3.3 - reference to 'change' should be to the 'proposed change or addition'. (9) M5 - some of the language does not match up with the language of the requirement itself. R3 requires that 'details for any proposed change or addition' be provided, while the measure refers to 'a summary of the future project or technical specifications of the proposed changes'. (10) M6 and M7 - would be helpful for the timeline in these measures to be complete i.e. 'within 30 days of receiving a request' instead of just 'within 30 days'. (11) R4 - reference to 'other owner' would be more precise to say the 'Transmission Owner, Generator Owner or Distribution Provider(s) providing the summary or technical justification'. (12) R4 – it is unclear in R4 whether the receiving owner is the party that is identifying the coordination issues, or whether the receiving owner is noting the coordination issues that are identified by the owner of the summary or technical justification. (13) R5 - not sure the timing of this part works. It requests that the TO, GO or DP shall have received a response prior to implementing any proposed changes or additions, but 1.1.4 and 3.3 are requirements that relate back to permanent changes that have already been made.
Group
Hydro One Networks Inc.
Sasa Maljukan
We do commend the drafting team for moving this standard in the right direction. 1) The focus of this standard seems to be on the process of executing the Protection System Coordination Study (PSCS) rather than the content of the PSCS, implying that entities don’t need to be told how to do this task. However we feel that a significant reliability gap exists by not outlining what elements need co-ordination (in accordance with the NERC Technical Reference Document “Power Plant and Transmission Protection Coordination, Revision 1”) and this should best be addressed now rather

than later by a FERC NOPR. We are not intending for the standard to be a “How” document but rather a “WHAT” – as in What elements need to be coordinated. As identified by the drafting team, there may be no evidence of miscoordination between traditional protections that detect faults, but for coordination of say generator loss of excitation protection settings or out of step relaying during a fault condition, it is necessary for entities to understand whether these should be considered in their PSCS. At the very least this standard should specifically point to elements whose coordination requirements exist in other standards. 2) In line with comment 1 above, the Purpose statement is confusing. “To coordinate Protection Systems for Interconnecting Elements such that Protection System components operate in the intended sequence during Faults”. Are the protection systems involved specifically for the Interconnecting Element, or between Facilities connected by an Interconnecting Element? So for instance according to the NERC White Paper “Power Plant and Transmission System Protection Coordination”, stator ground protection may need to be coordinated with transmission system faults. Stator ground is a generator protection – so is that in scope of the PSCS specified in the standard since this protection is a generator protection, not an Interconnecting Element protection? 3) For Requirement R3.1, it is not clear what is meant by “Details….. associated with the Interconnecting Element or at other Facilities…..” What is the burden of proof associated with this requirement? In the long term planning horizon, is it implied this assessment be made through short circuit studies? We believe it would be proper to associate R3.1 solely with changes/additions “either at an existing or new Facility associated with the Interconnecting Element….”. Changes at other Facilities could mean 1, 2 or 3 busses away and we believe if these changes were significant, they would manifest themselves in a significant change in Fault current levels. Furthermore, in an audit, the burden of proof lies with the owner to show these changes “at other Facilities” don’t affect coordination. We suggest the following change to the wording: “Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s) where such changes result in a change of 10% or greater in either single line-to-ground or three-phase fault current as defined in R2.2.” Section 1.2 – Retention Period: This section specifies that the default retention period for this standard is “since the last audit”. Consequently, we don’t understand what is the purpose of the second sentence in this section (i.e. “For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.”) because there is no such instances.
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
In draft #3 of the standard, there was requirement 4.2 which stated that “Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.” There does not seem to have this language in this draft. Was it the SDT intention not to require the entity proposing a change (defined in requirement 3.1) to get agreement with owners of Interconnected Elements prior to implementation?
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
Comment for Draft 4 of PRC-027-1 – Protection System Coordination for Performance During Faults Measure M9 requires the response to “address” any identified issues. Can the SDT provide examples of a range of responses that would “address” identified issues (even in a guidance document)? For example, if the TO does not agree with the entity that submitted the “identified issues” that the issues are truly valid, can the TO merely respond by a statement saying that the issues are unfounded. Would this be “addressing” the issue or would the TO in this example be required to provide more information such as additional study results? In addition, after providing such additional study results, would the TO then be done with addressing the issue, or would a follow-up

meeting be required if the entity that submitted its concern still disagrees? Please elaborate on what the SDT expects from “address any identified issues.”
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
The definition of interconnecting element needs to make clear that not only does it have to be a BES element to BES element connection, not just a BES element connecting two different entities. For example a TO to DP shared facility might have some BES elements that are shared, but that really just connect BES to non-BES equipment.
Individual
Michael Moltane
ITC
We vote "Negative" on Draft 4 of PRC-027-1 primarily due to enormous increase in administrative burden with no appreciable gain in system reliability. We agree with SDT there is reliability benefit to performing these tasks. However, as the SDT members stated at presentations to RFC Protection Subcommittee and to NATF Workshop, utilities are already doing this work. The SDT’s own rationale states “no evidence there is widespread miscoordination of Protection Systems”. Therefore, the only outcome of this standard is that utilities will greatly increase administrative burden to become auditable. Figure 5 Note statement “Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T” disagrees with Figure 5 and with the first sentence of the last two paragraphs. Figure 5 shows TO S owns breaker C in Station 1 and by implication also the Protection Systems associated with breaker C. The first sentence of the last two paragraphs specify the review of coordination of the Protection Systems of breakers C and D. Please remove the quoted sentence from the Figure 5 Note. We disagree with changing Figure 5 Interconnecting Element from the common bus to the connection between the bus and breakers. As is, R3 does not require TO R to act as a conduit for exchanging information between TO S and GO T. The last sentence of second-to-last paragraph in Figure 5 attempts to require TO R to act as the conduit for information between the other parties, but this is not found anywhere else in the standard. Please make the common bus the Interconnecting Element and remove statement in Figure 5 specifying TO R is to be a conduit for this information. As R3 is written, this requires each owner on the bus to share changes with each other owner. This should be a reasonable expectation. Why does Figure 3 not specify TO R develop settings for breakers A and B with DP S reviewing for coordination over breaker C and transformer? Why is this coordination around the Interconnecting Element not included? We had similar comments to Draft 3 but our question may have been misinterpreted. What is benefit of Facilities part b)? What is the SDT trying to exclude or include by using the statement “that require coordination”? Is it the intent of SDT in R5 to leave open possibility of implementing proposed change without receiving a response pursuant to Requirement R4? R5 only requires addressing identified coordination issues if the entity “received a response pursuant to Requirement R4”. R4 allows the entity 90 days to respond. The entity making the change could implement the change in this 90 day window without receiving a response and still be compliant. R1.1.3 allows the two parties to reach agreement on the PSCS date which may typically allow time for such exchange, but the entity making the change could move up the change implementation date or the agreed upon date could be less than 90 days prior to the implementation date. R3.3 and R1.1.4 leave out a requirement for a PSCS by the owner with the emergency/commissioning change. R1.1.4 specifies only the party “notified of a change as described in” R3.3 shall perform a PSCS. Is this the intent of the SDT?
Individual
Winnie Holden
PSEG
1.Replace “technically justify” and “technical justification” language is several places. a.Parts 1.1.2, 1.1.3, and 1.1.4 require an owner, as an alternative to performing a PSCS, to “technically justify why such a study is not required.” We recommend that the phrase “technically justify” be replaced

with “state” in Parts 1.1.2, 1.1.3, and 1.1.4. The phrase “technically justify” conjures up detailed documentation, whereas an expert’s statement that is read by another expert (see R4) may be totally understandable and satisfactory. b.The last sentence in M1 should have the phrase “of a technical justification” stricken so that it reads “Acceptable evidence for not performing a PSCS as specified in Parts 1.1.2, 1.1.3, and 1.1.4 may include, but is not limited to, documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any aspect of coordination.” c.Part 1.2 should also have the phrase “technical justification” removed and be rewritten as follows: “Within 90 calendar days after the completion of Requirement R1, Part 1.1, either provide to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s): a summary of the results of each PSCS performed, including, at a minimum, the Protection Systems reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed; or a statement why a PSCS is not required. d.M2 should have the phrase “technical justification” replaced with “statement why a PSCS is not required.” e.In R4, an owner’s “technical justification” must be confirmed by the other owners of Facilities with protection Systems associated with the Interconnecting Element – either with no issues or with issues noted (see the last two bullets in R4). Since one owner’s experts will be communicating with another owner’s experts, a statement why a PSCS is not required is sufficient. We request that “technical justification” be replaced with “statement” the first sentence in R4. We also request that “technical justification” be replaced with “statement why a PSCS is not required” the third bullet fourth bullet in R4. 2.In R2, the team’s rationale for naming the Transmission Owner as the entity responsible for performing the short circuit studies is that they maintain the data necessary to perform the studies – see the R2 textbox. This statement is not correct. Short circuit data under MOD-032-1 will be collected by a Planning Coordinator or a Transmission Planner. In addition, Generation Owners are responsible for some of the data – see Attachment 1 in MOD-023-1, “short circuit” column. However, short circuit data will be used by Transmission Planners in TPL-001-4. In that standard, Transmission Planners are required to perform short circuit analyses to determine whether existing or planned circuit breakers have the interrupting capability for the calculated Fault current. See TPL-001-4 Requirement R2, Part 2.3 as well as Part 2.6, which identifies when prior studies may be used. The SDT should recognize the requirements in TPL-001-4 and take advantage of Fault Current calculations already required by this standard. By having the Transmission Planner perform the Fault current calculation, a consistent short circuit database across a large footprint, such as PJM, will be used. Therefore, “Transmission Owner” should be replaced with “Transmission Planner” in R2. In addition, “Transmission Planner” should be added as an Applicable Entity.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; and PPL Generation, LLC, PPL; Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. There remains the technical issue that TO changes do not typically affect GOs’ Protection System configurations or settings. Requiring GOs to perform PSCSs would not improve system coordination during faults, especially since everything involving tripping elements in the intended sequence (the stated purpose of PRC-027-1) is in the TO’s system. Currently, the only inputs that GOs need from TOs, are the fault current at interconnecting buses (affects the GO’s arc-flash studies) and the grid X/R ratio. PRC-001 coordination for TO changes would typically consist of GOs obtaining these two values and not requesting and analyzing the detailed TO information cited on p.23 of PRC-027-1 (“power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings”). Consequently, GOs should have no Protection System coordination duties other than reporting and receiving information on planned changes prior to implementation as per PRC-001. In concept, the individual requirements of PRC-027-1 are logical; however, significant efforts will be required for documentation of coordination across Registered Entities which will be required to achieve the totality of (R1-R5) intent. The

concern is that actual system coordination is currently built in to TO/GO processes and that the PRC-027-1 requirements do no more than place focus on documentation of such processes of coordination activity rather than the system coordination itself.
Group
Seattle City Light
Paul Haase
Sacramento Municipal Utility District (SMUD)
Seattle has concerns with this draft in addition to those identified in SMUD's comments. In particular, the present draft creates difficulties for entities with short transmission lines that require use of communication-assisted (pilot) relaying schemes in order to provide proper sectionalizing (coordination) of the transmission system during a fault event. The draft does not address the coordination of pilot schemes, and their backup relays (67N, e.g.). The 67N relays, located at the different buses, cannot be coordinated in our system (and others). In the absence guidance in the draft, Seattle recommends that the language be clarified to allow miscoordination of the backup relays as long as the pilot scheme is in place.
Individual
Alice Ireland
Xcel Energy
1. It is assumed that PRC-027 PSCS requirements will also apply for Interconnecting Elements between the Transmission System and the high side of the final aggregating step up transformer for BES dispersed generating facilities as described in Inclusion I4 of the recently passed BES Definition. If this indeed the case, an additional bullet should be listed in PRC-027 R3.1 as follows: [• At BES dispersed generating facilities, changes to the aggregating step up transformer or aggregating system which result in a change in impedance.] It may also be beneficial to include a diagram of a typical dispersed generation facility and relevant discussion in the Application guideline similar to that provided for the conventional generator configuration as shown on Fig 2 on page 28 of 32 of the standard. 2. PRC-005-2 and PRC-005-3 have recently been approved by NERC and both of these versions of the Protection System Maintenance Standard exclude the protection systems for power plant system-connected auxiliary transformers from their applicability. This exclusion of the system-connected auxiliary transformer from PRC-005 maintenance requirements is also described in the associated PRC-005 Supplementary Reference Document. In contrast, PRC-025 was also recently approved by NERC and specifically includes relay loadability setting requirements for relays protecting generating plant system-connected auxiliary transformers which are capable of providing plant electric loads during full power operation of the plant. Is it the intention of the drafting team that PRC-027 PSCS requirements apply to Interconnecting Elements that serve to connect the Transmission System to generating plant system-connected auxiliary transformers such as 345 KV line connecting a substation 345 KV breaker and a half scheme node to a plant 345KV/4KV auxiliary source transformer? We do not have a strong opinion whether a PSCS should be required for such interconnections. However, based on the inconsistent treatment provided to these system-connected auxiliary transformers in other standards as cited above, we believe it not only desirable but necessary that the PRC-027 application guideline explicitly state the drafting team’s intentions concerning PSCS requirements for the interconnection between the Transmission System and power plant system-connected auxiliary transformers.
Group
Dominion
Connie lowe
Dominion has no comments and supports PRC-027-1.
Individual
Anthony Jablonski
ReliabilityFIrst

ReliabilityFirst votes in the affirmative for the draft standard but offers the following comments for consideration: 1. Requirement R1, Part 1.2 - ReliabilityFirst believes the reference to "... technical justification pursuant to Requirement R1, Part 1.1" should be changed to correctly reference Requirement R1, Part 1.1.2 and 1.1.3. 2. VSL Requirement R1, Part 1.2 - Requirement R1, Part 1.2 specifically requires "...at a minimum, the Protection Systems reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed; or the technical justification.". For clarification, if an entity fails to include one of these items in the summary more than 30 calendar days, does the entity fall under the "Severe VSL"? If this is not the SDTs intent, the VSLs will need to be drafted to address entities failing to include the mandatory items.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
ATC is recommending an affirmative vote with the following clarifying comments: a. The text in sub-requirement R1.1.2. states "...10% or greater change in Fault current..," however, it is unclear what is considered the baseline. ATC recommends that this be clarified so that it is stated against what point in time the change is being measured. b. The text in Requirement R5 currently states "...shall address any identified coordination issue(s)..." which is vague and could lead to the unlikely event of an uncooperative party either stalling or prohibiting the work. ATC recommends this be clarified or re-written as "...shall address or acknowledge any identified coordination issue(s)..."
Individual
Andrew Z. Pusztai
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Individual
Chris Scanlon
Exelon Companies
Consistent with previous comments, we continue to believe that PRC-027 is overly complex and its implementation will result in an unfair burden to registered entities that will not provide a commensurate increase in BES Reliability. The detailed flowchart included in the draft depicts a complex relationship between the requirements that will be difficult and costly to document in actual practice. Each protection activity that requires PRC-027 compliance tracking will have a unique trajectory through the flowchart creating a complex documentation record to prove that compliance efforts have indeed satisfied the flowchart. That such an intricate flowchart is required to explain the compliance process illustrates this point. From the standpoint of Transmisson Owner, we believe that developing a process to comply with this standard will prove to be a costly venture requiring additional staff just to track the status compliance items and doing little to improve the reliability of the BES. As written, the standard continues to be vague and in practice will be subject to individual interpretation by entities and Compliance Authorities alike. Requirement 3.1 does not provide sufficient clarity about what magnitude of impedance change would trigger an entity to provide details to other entities associated with a Protection System of an interconnected element. We believe that the decision of whether a change is significant should be left to the sound engineering judgment of the Protection engineers. We suggest the following modification to R3.1, Changes to a transmission system Element that result in a significant change in sequence or mutual coupling impedance. Changes to generator unit(s) that result in a significant change in impedance. Changes to the generator step-up transformer(s) that result in a significant change in impedance. Requirement 5 What will qualify as evidence of "addressing" an identified issue? Measurement 9 is

not helpful in providing clear direction to entities as to what is acceptable evidence that an issue identified by R4 has been addressed. What options are availble if an entity receiving notification of an issue does not agree there is an issue?
Group
ACES Standards Collaborators
Jason Marshall
(1) We continue to believe that this standard should only require coordination between separate companies and not separate functional entities that may be under one corporate umbrella. We are particularly concerned about coordination requirements placed on smaller entities such as generation and transmission cooperatives where a single protection engineer may be responsible for protection system coordination for all transmission, generation and distribution interconnections. Having to document coordination among a single protection engineer is an unnecessary compliance burden on these small entities and the reliability benefit is not commensurate with the additional compliance costs required of the small entity. We ask the drafting team to consider an exception process for small entities to relieve them of unnecessary compliance burdens if this requirement persists. (2) We disagree with the definition of “Interconnecting Element” because the second part of the definition would require a Registered Entity registered as multiple functional entities to coordinate with itself. This definition does not take into account smaller entities that may be registered for multiple functions, but still only have a single protection system engineer. This poses an issue for smaller entities to prove compliance for this coordination among its functions. For example, why should such a small entity be required to show additional evidence of coordination between its functions of TO, GO, and DP for its relaying schemes that a single Protection System engineer determined was appropriate. The settings and schemes themselves are evidence of coordination, and this standard is asking for additional documentation that does not benefit reliability. (3) Requirement R2 should specify an initial performance period for initial compliance consistent with R1. R1 establishes that a Protection System Coordination Study should be completed within 60 months of the effective date of the standard. However, R2 only requires that the TO perform a short-circuit study once every 60 months. Thus, does this mean that the initial short-circuit study for compliance purposes has to be completed prior to the effective date of the standard, or 60 months after the effective date or some time period in between? Given this ambiguity, there will be inconsistent compliance outcomes from region to region and registered entities are bound to interpret this differently than compliance enforcement authorities. To avoid similar issues of compliance violations when PRC-005 was first implemented, we request that the drafting team establish a clear initial compliance period in the implementation plan. (4) R2, part 2.1: We recommend removing short circuit studies for this standard, as there are other standards that require short circuit calculations and data submittals, such as the MOD-B project and short circuit studies and analysis that are required under TPL-001-4. These other standards address short circuit data and analysis and we are concerned of potential overlap and possible double jeopardy of including short circuit studies in PRC-027. (5) We have concerns with the use of “proposed change or addition” for Part 3.1 and believe it will lead to inconsistent enforcement. The term “proposed” is vague. When does an idea for a modification become a proposed change that must be communicated to other TOs, GOs and DPs? For example, if a new generator interconnection is requested and studies indicate that it would require a transmission modification that changes a transmission system Element and alters it impedance, is this a proposed change? When would it become a proposed change, when the interconnection agreement is signed? When the request is submitted? The requirement is not clear which will lead to different opinions between registered entities and compliance enforcement personnel. Additional clarity is needed for when a change must be communicated. (6) The Guidelines and Technical Basis section of PRC-027 has raised several questions. In the purpose, the second paragraph states that “this standard requires that separate registered entities communicate with each other to coordinate Protection System components on existing Interconnecting Elements,” however, we are concerned that the definition of Interconnecting Elements is contradictory. Section “b” of the definition is based on the same registered entity that represents multiple functional entity responsibilities. Which is it? The technical justification states that the standard should apply to separate entities, but the proposed definition states that the standard applies to separate functions, even if those functions are registered to a single entity. We ask that the drafting team provide clarification and suggest that the standard is

applicable to corporate entities and not separate functional entities within a corporate entity. (7) We believe Part 3.2 meets P81 criteria and it should be struck. It is administrative in nature and meets criterion B4 - Reporting because it requires reporting to a third party and the reporting does not provide a material reliability benefit. (8) Requirement R4 meets P81 criteria and should be struck. It is administrative in nature and provides no reliability benefit. More specifically, it meets criterion B4 - Reporting because it requires reporting to a third party without material reliability benefit and criterion B1 – Administrative because it requires responsible entities to perform an administrative function that does not support reliability and is needlessly burdensome. This requirement should be struck. The real reliability requirement is to address coordination issues, which is already covered in R5. (9) The technical justifications for not updating the PSCS provided on page 21 of the Application Guidelines should be codified in the standard. We agree with the technical justifications. For example, there is no need to update a PSCS for a differential protection system for a greater than 10 percent change in fault current per Part 1.1.2. The approach could be modeled after PRC-023 Attachment A. (10) Thank you for the opportunity to comment.
Group
Duke Energy
Colby Bellville
Duke Energy would like to thank the SDT for its efforts on this project.
Individual
Bob Thomas and Kevin Wagner
Illinois Municipal Electric Agency
The proposed standard is incorrectly defining the tap line serving a distribution load as an “Interconnecting Element”. The tap line in this case is not a BES Element. PRC-027-1 should only apply to interconnecting TOs or to interconnecting TOs and GOs. The only coordination that makes sense between the TO and the DP is making sure the TO does not trip its BES Element (line) for a fault located within the DP. In this case, the TO and DP would be responsible for detecting and coordinating for a fault on a non-BES element (which is not an “Interconnecting Element” as defined by the proposed standard). The proposed standard seems to attempt to redefine a DP-owned transmission Protection System as a system that simply detects a fault on a BES Element (Interconnecting Element) and requires coordination. That is not consistent with the FERC-approved interpretation of what constitutes a Protection System; i.e., detect BES fault and interrupt BES fault current. IMEA appreciates the need for proper relay coordination between the players (TOs and GOs) on the grid, but this proposed standard seems to incorrectly apply a coordination requirement to the interconnected DPs. Also, during the 12/5/13 PRC-027-1 Webinar, it was noted that the Protection System Coordination Study (PSCS) specified in Requirement 1 must be performed by each party at the ends of an Interconnecting Element. This seems like overkill. The owner of the Interconnecting Element should take the lead on the PSCS, with coordination/support/cooperation of course provided by the interconnected party.
Individual
Joe Tarantino
Sacramento Municipal Utility District
• Requirements are not ‘self-contained’ there are several requirements that reference another process in other requirements; • Allegedly this standard only applies to interconnections, this is not clearly evident in the Interconnected Element definition; • Requirement R1.2 references another owner. SMUD views this as an administrative burden having to document to the ‘other owners’ communication when the ‘owners’ Protection System Coordination Study is conducted by one responsible party. • Several of the requirements contain a ‘zero defect’ concept where if a date is missed it results in an automatic violation.
Group
Florida Municipal Power Agency
Frank Gaffney

To us, relay coordination is very important to reliability, more so than many other standards. So, at least in FMPA's view, this standard may actually not go far enough in two ways: 1) Clearing the fault within the critical clearing time: yes, the TPL standards require that we plan the system to be stable considering actual fault clearing times with consideration of a failure of a protection system looking > 1 year into the future; and yes, FAC-011 requires us to define SOLs that are stable in consideration of clearing times for single contingencies (but without protection system failure); but, there is little in the standards that requires us in the operating horizon to make sure we are clearing a fault fast enough to avoid instability for a single line to ground fault with a protection system failure. Maybe PRC-027 is not the right standard to accomplish this goal; however, we would have liked to have seen the purpose of this standard talk about clearing the fault quickly considering a protection system failure as the highest priority, with the proper sequence of tripping as a secondary priority. As protection engineers, we have seen times where we purposely would allow over-tripping for backup protection for some faults to make sure we cleared the fault within the critical clearing time. The standard as proposed makes "operate in the intended sequence" the only priority of the standard and as such may not allow continuation of this practice. 2) Coordinating all BES protection, not just at the boundaries: Another important consideration is that fault clearing, and proper sequencing of fault clearing, is important at all parts of the BES, not just at the boundaries between registrations. The standard as written follows the example of the existing PRC-001 it is replacing which requires coordination only at the boundaries between entities. The standard does expand this scope by requiring vertically integrated utilities to define boundaries between their registrations and coordinate protection systems across those boundaries (e.g., between the generators and the transmission at the interconnection) (as we have witnessed from the GO TO effort, defining those boundaries is not straightforward and is open to conflict). However, as stated previously, what makes the boundaries between registrations different than any other location on the BES from a critical clearing time and sequence of operation perspective? If Protection System coordination throughout the BES was instead required, there would be no need to defined these boundaries and would reflect its importance to reliability. FMPA made these same comments on the prior ballots of this standard, but, to no avail on the SDT. It strikes us as quite odd, when we compare the recently balloted PRC-002 on disturbance monitoring, which has de minimus impact on reliability, and this PRC-027 which is very important for reliability, that the PRC-002 standard is longer, more detailed, and in some ways more onerous (14 requirements) than this proposed PRC-027 (4 requirements). FMPA believes that PRC-002 should not be a standard at all due to its de minimus impact, but also believes that PRC-027 does not go far enough due to its important to reliabiliy. FMPA believes that priorities are misplaced in standards development.
Group
SPP Standards Review Group
Robert Rhodes
We are concerned that the standard as proposed offers a formalized, very prescriptive structure without providing significant reliability gains since most of the requirements are currently captured by the industry in good business practices. We would prefer to have a more generic, less prescriptive standard that provides more of a guideline of what coordination is required rather than the complicated, involved documentation that is required in the current draft. We believe Requirement R1.1.1 is duplicative with Requirements R2 and R2.1 because they are both based on a 60-calendar month time frame. Furthermore, R1.1.1 is a one-shot requirement that would no longer be applicable after the first 60-calendar month cycle. Therefore R1.1.1 should be deleted from the standard. We are confused by the language in Requirement R1.1.2 which appears to require a PSCS within 12 months of determining, or being notified of, a 10% change in fault current. First of all, haven't you already done the study when you determine that the change exists? Secondly, does this require a study within the first 12 months following the standard becoming effective if no study currently exists? Otherwise, a study is not required for 60 months plus the 12 month grace period. Additionally, for smaller entities, especially municipals or cooperatives, without full-time staff to conduct full-blown PSCSs, 12 months may be imposing a very tight schedule on them given considerations for seasonal issues, vendor availability, bidding and approval processes. On Page 24 in the Guideline and Technical Basis section under Requirement 4 in the 1st line, insert a space between R4 and directs. We suggest that all references to calendar days or calendar months which

are preceded by a specific number of days or months be hyphenated. For example, 30-calendar days, 60-calendar days, 12-calendar months, 60-calendar months, etc.
Group
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia
Wayne Johnson
a) R3 should state what is to be provided. As such “the following information” after “provide” in the 1st line of R3. b) R3.1 is confusing because of the use of “either” and two instances of “or” which follow. Suggest removing the ‘either’ and modify ‘existing or new Facility’ to ‘existing/ new Facility’ Also, no colon introduces the bulleted text c) R3.3 wording needs improvement. A reader is looking for what information must be provided as they goes from R3 to 3.1, 3.2, and 3.3. Beginning 3.3 with “Within 30…” makes it difficult to determine what is to be provided. Suggest moving ‘within 30 days’ to the end of the sentence. d) It would be helpful if, where possible, the boxes in the Flow Chart indicated the owner to which it applies. For instance, the box for R2.2.1 should say ‘The TO shall ….’ e) In order to prevent potential confusion, would the SDT consider modifying R4 & R5 to include exclusions for a PSCS performed as a result of “other changes” specified in R3.3. f) The flow chart is helpful to demonstrate the flow of the desired process and the triggers for study review. Minimizing the twists and turns in the presentation would make it even better. Also, there is a short circuited section around box R2.2.1 and the “receive notice of > 10%...” that should be corrected. Please consider replacing that section with the diagram provided under separate cover to the Chair and NERC Standards Coordinator.
Group
Western Electricity Coordinating Council
Steve Rueckert
Over time, Part 1.1.1 of Requirement R1 will become meaningless. After the standard has been effective for five years, it will be outdated unless the intent is to continue to assess whether or not all entities have completed all Protection System Coordination Studies for the first time. Is this something that should be in the implemetnation plan rather than a requirement?
Individual
Rich Salgo
NV Energy
In the rationale statement for R1, part 1.1.1, the SPCSDT acknowledges that there is no “widespread miscoordination of Protection Systems associated with Interconnecting Elements that warrants a shorter time frame,” yet nevertheless specifies a requirement to conduct a PSCS within 60 months for instances where no PSCS exists. Given that there is no widespread miscoordination issue, we suggest that suitable evidence other than a formal PSCS should suffice. Suggest the following language for 1.1.1: "Within 60 calendar months after the effective date of this standard, if sufficient evidence of coordination for that Interconnecting Element does not exist." Also, we are concerned about the Applicability section as it pertains to interfaces between the transmission and distribution systems of an Entity. We believe that, for example, a 138/12.5kV substation transformer should not qualify as an Interconnecting Element, and request clarification in the Applicability section that provides some certainty on that point.
Group
US Bureau of Reclamation
Erika Doot
The Bureau of Reclamation (Reclamation) appreciates the drafting team’s efforts to address stakeholder concerns that an engineering department may perform analysis from both the Transmission Owner (TO) and Generator Owner (GO) perspective. However, adding a note to the rationale for R1, R3, and R4 that “[i]n cases where a single group performs an overall coordination study for a give Interconnecting Element, a single document … is sufficient for use by all entities” does not appear to fully address the concern. For example, one signed and dated document is

unlikely to demonstrate that the GO-arm of the entity reviewed the summary results of the study within 90 days as required by R4. Reclamation requests that the requirements and measures clarify how to document the coordination of a study when an entity acts as a GO on one side of an Interconnecting Element and a TO on the other side of the Interconnecting Element. Reclamation also requests clarification on the scope of R3.1, which references any change at a facility that “modifies the conditions used in the coordination of Protection Systems associated with Interconnecting Elements.” The Application Guidelines associated with R1 suggests that technical justifications may be used to exclude certain differential elements, distance elements, supervised overcurrent elements, and reverse power, definite time, and/or time overcurrent elements from the Protection System Coordination Study (PSCS) requirement. However, R3 appears to require notifications for new installations or modifications of these types of elements when they do not impact conditions for detecting and clearing faults and would not require a PSCS. Reclamation suggests that R3.1 be updated to refer to notifications “when the proposed change impacts the conditions for detecting or clearing faults” rather than “when the proposed change modifies the [seemingly any] conditions … used in the Coordination of Protection Systems.” Reclamation believes that R3.1 should require, “Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities, when the proposed change impacts the conditions for detecting or clearing faults on the BES elements used in the coordination of Protection Systems associated with the Interconnecting Element(s)."
Group
Bonneville Power Administration
Andrea Jessup
BPA reiterates our previously stated concerns expressed in draft 3 comments. BPA concerns stem from two basic issues. First, PRC-027 prevents us from using our judgment to determine when and how to review relay coordination on our interconnections with neighboring entities. This reduces our efficiency and eliminates the flexibility that allows us to most effectively interface with each of our neighboring entities. If it could be shown that there would be an increase in the reliability of the bulk electric system based on this standard, perhaps this standard would be acceptable, but we are not aware of any problem that this standard will correct. The second basic issue that causes BPA concern with this standard is that it contains requirements for which the details of compliance are not adequately addressed. BPA recommends that the meaning and details of the terms Interconnecting Element, Protection System Coordination Study, and interconnecting bus be more clearly defined. These are some of the major terms used in the standard. The standard also relies heavily on the Guidelines and Technical Basis to explain its meaning, but this too falls short and cannot possibly cover every different situation that will be encountered in the application of the standard. Because of these fundamental issues, BPA finds PRC-027 unacceptable. BPA’s suggestion is to draft a much more basic standard. A simple requirement, such as Each Transmission Owner (TO) that owns a Protection System which requires coordination with a Protection System owned by a neighboring TO to prevent the scheme from misoperating shall reach agreement with the neighboring TO on how to set the protective relaying scheme in order to minimize the possibility of it misoperating, along with some simple measures for documentation would be sufficient to insure that neighboring entities work together to coordinate their protection systems while still allowing for flexibility and engineering judgment to be applied.
Individual
John Brockhan
CenterPoint Energy
1. For a Registered Entity that represents multiple functional entity responsibilities, CenterPoint Energy believes the proposed definition for Interconnecting Element, as stated, would require an entity to perform a Protection System Coordination Study (PSCS) on every BES Element in its system. We recommend the wording in item “b)” of the definition be deleted. The concern the SDT appears to be addressing is the coordination of transmission protection systems with generation protection systems. We do not believe a mandatory requirement is needed to address communication and work processes within a vertically integrated entity. NERC Reliability Standard PRC-004 addresses transmission and generation misoperations and is a vehicle that is already in

place that can be used to address Protection System coordination needs, should root analysis identify such a need. In a vertically integrated entity, a corrective action plan would include both transmission and generation protection aspects. 2. CenterPoint Energy recommends that Distribution Providers be removed from the Applicability section. It appears that there would be very few, if any, distribution protection systems that would be applicable to the proposed requirements. We are not aware of any distribution protection systems that must be coordinated with transmission Protection Systems to allow for the proper functioning of the transmission Protection Systems. 3. CenterPoint Energy recommends that the trigger to conduct a Protection System Coordination Study for a 10 percent or greater change in fault current be only for increases in fault current; that is, decreases in fault current should not require entities notify other entities and not require the entities to conduct Protection System Coordination Studies. Protection Systems must operate for a variety of reduced fault current levels in normal system operation, as well as operation during and after major storms. For example in normal operation, there is a substantial decrease in fault current when a generating unit or an autotransformer is unavailable. In storms (hurricanes, extreme cold, etc.), even greater decreases in available fault current can occur. 4. While coordination of Protection Systems is a reliability consideration, CenterPoint Energy recommends reevaluating the need for this standard with consideration that this could instead be addressed by misoperation analysis. NERC Reliability Standard PRC-004 addresses transmission and generation misoperations and is a vehicle that is already in place that can be used to address Protection System coordination needs, should root analysis identify such a need.
Individual
Brian Evans-Mongeon
Utility Services
The applicability section for Distribution Providers requires more specificity. How will a DP become aware that their Protection System requires “coordination for isolating” faulted Interconnecting Elements? Suggest adding language requiring the owner of the Interconnecting Element to notify the Distribution Provider that their Protection System is required to isolate faults on the Interconnecting Element. This will place the burden on the owner of the protected Interconnecting Element to ensure that element is properly protected.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
R5 does not require that “identified issues” associated with technical justifications be addressed. We believe the addressing of those needs to be included.
Individual
Spencer Tacke
Modesto Irrigation District
The definition of Interconnecting Element needs to be revised, specifically part b). It is unclear what the intent of part b) is. If you interpret part b) the way it is written, it seems that part b) would exclude BES elements that don't join separate entities if the entity is just a transmission owner, or just a generator owner, etc. Thank you.

Additional Comments:

Tampa Electric
James Rocha

The violation severity level even on insignificant elements should not be based on time but based on the risk to the BES. The requirements create a large documentation and scheduling burden without improved reliability, if passed as proposed.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Coordination of Protection System Performance During Faults**
2. **Number:** PRC-027-1
3. **Purpose:** To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection System components operate in the intended sequence during Faults.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 below)

   4.2. Facilities:

   4.2.1 Protection Systems installed for the purpose of detecting Faults on BES Elements, and isolating those faulted Elements
5. **Effective Date:** See Implementation Plan
6. **Definitions:**

   Interconnecting Element

   A Bulk Electric System (BES) Element that electrically joins Facilities:

   a) owned by separate Registered Entities, or

   b) assigned to different functional entities (Transmission Owner, Generator Owner, or Distribution Provider) of the same Registered Entity

B. Requirements and Measures

Rationale for Requirement R1:

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement a process to coordinate its BES Protection Systems to operate in the intended sequence during Faults. The process shall include, at a minimum: *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

1.1. A method to review and update data required to develop Protection System settings.

1.2. A quality assurance or review process of the Protection System settings.

1.3. A set of minimum triggers to prompt a review of existing Protection System settings. Specified triggers may be time-based, condition-based, or a combination of the two.

1.4. A procedure to communicate the Protection System settings with Transmission Owners, Generator Owners, and Distribution Providers associated with Interconnecting Elements and seek concurrence that there are no identified coordination issues.

1.5. A procedure to verify any identified coordination issue(s) associated with proposed Protection System settings are addressed prior to implementation.

M1. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has implemented its process to coordinate its Protection Systems, in accordance with Requirement R1 and its Parts.

Rationale for Requirement R2:

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, within 60 calendar months after the effective date of this standard, have documentation that the Protection Systems for the following Elements are coordinated to operate in the intended sequence for clearing faults. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

2.1. Interconnecting Elements associated with Transmission operated at 200 kV or above.

2.2. Interconnecting Elements associated with BES Generating resource(s) with gross plant/facility aggregate nameplate rating greater than 75 MVA.

2.3. Any monitored Facility of an Interconnection Reliability Operating Limit (IROL).

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity coordinated the Protection Systems for the Elements identified in Requirement R2 within 60 calendar months of the effective date of this standard.

Unofficial Comment Form

Project 2007-06 System Protection Coordination
PRC-027-1 (Preliminary Draft 5)

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on this preliminary draft 5 of standard **PRC-027-1 – Coordination of Protection System Performance During Faults**. The electronic comment form must be completed by **8 p.m. Eastern, Tuesday, October 21, 2014.**

If you have questions, please contact Al McMeekin, NERC Standards Developer by email at Al.McMeekin@nerc.net or by telephone at (404) 446-9675.

The project page may be accessed by clicking here.

Background Information

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: "*To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection System components operate in the intended sequence during Faults.*" This standard incorporates and clarifies the coordination aspects of Requirements R3 and R4 from PRC-001-1.1. Following draft 4, FERC staff from the Office of Electric Reliability raised significant concerns on the posted draft. The primary concern was that the proposed standard did not address the coordination of Protection Systems within a Transmission Owner's footprint, referred to as "internal" or "intra-entity" Protection Systems. Following those discussions, the SPCSSDT prepared this preliminary draft 5 of PRC-027-1 and now seeks stakeholder input on this proposal during a 21-day informal comment period.

Draft 5 of PRC-027-1 modifies the applicability of the standard to include "*Protection Systems installed for the purpose of detecting Faults on BES Elements, and isolating those faulted Elements*," whereas, prior drafts of the standard limited the applicability to "*Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements.*" This change to the applicability covers the coordination of Protection Systems for all "internal" or "intra-entity" connections between BES Elements.

Prior drafts of PRC-027-1 would not have been easily adaptable to this change, and as a result, the drafting team has altered its approach in the draft. The draft now consists of two proposed requirements.

Requirement R1 mandates an entity to implement a process to coordinate its BES Protection Systems, and stipulates certain attributes that must be included in the documented coordination process. Because entities' Protection System designs and philosophies vary greatly, the drafting team has included necessary flexibility in developing the coordination processes.

Requirement R2 mandates an entity have documentation, within 60 calendar months after the effective date of the standard, that the Protection Systems for the Elements specified in Requirement R2 are coordinated. Requirement R2 is a one-time performance requirement necessary to establish a baseline of coordination.

21-day Informal Comment Period

For this informal posting, the drafting team is soliciting stakeholder feedback on the scope and work product developed thus far. The drafting team intends to take this informal feedback and use it to begin formal development of draft 5 of PRC-027-1 in November. The electronic comment form must be completed by **8 p.m. Eastern Tuesday, October 21, 2014**. Entities may communicate additional feedback directly to the drafting team through its open meetings leading up to the formal posting in November.

Please enter comments in simple text format. **Bullets, numbers, and special formatting will not be retained** (even if it appears to transfer formatting when copying from the unofficial Word version of the form into the official electronic comment form). If you enter extra carriage returns, bullets, automated numbering, symbols, bolding, italics, or any other formatting, that formatting will not be retained when you submit your comments.

- Separate discrete comments by idea, e.g., preface with (1), (2), etc.
- Use brackets [] to call attention to suggested inserted or deleted text.
- Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.
- **Do not use** formatting such as extra carriage returns, bullets, automated numbering, bolding, or italics.
- **<u>Please do not repeat other entity's comments</u>.** Select the appropriate item to support another entity's comments. An opportunity to enter additional or exception comments will be available.
- If supporting other's comments, be sure the other party submits comments.

Questions:

1. Do you agree with the concept of requiring a process to address the coordination of Protection Systems (Requirement R1)? If not, please provide the basis for your disagreement and your proposed alternative(s).

   ☐ Yes
   ☐ No
   Comments:

2. Do you agree that Parts 1.1 through 1.5 of Requirement R1 are essential elements of a successful coordination process? Are there others that should be included? If not, please provide the basis for your disagreement and your proposed revisions, or other additions.

   ☐ Yes
   ☐ No
   Comments:

3. The coordination process **will** include a set of minimum trigger(s) (Part 1.3) to review existing Protection System settings. These triggers will be developed by the drafting team during the standard development process. Please provide any suggestions for appropriate triggers.

   Comments:

4. Requirement R2 mandates entities have documentation, within 60 calendar months after the effective date of the standard, that the Protection Systems for the specified Elements in Parts 2.1 through 2.3 are coordinated. Do you agree with the chosen Elements and do you have any suggestions for others? If not, please provide the basis for your disagreement and your proposed revisions, or other suggestions.

   ☐ Yes
   ☐ No
   Comments:

5. Do you agree with the proposed Measures? If not, please provide the basis for your disagreement and your proposed revisions.

   ☐ Yes
   ☐ No
   Comments:

6. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

   Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1 (Preliminary Draft 5)

Informal Comment Period Now Open through October 21, 2014

Now Available

A 21-day informal comment period is open for preliminary draft 5 of **PRC-027-1 – Coordination of Protection System Performance During Faults** through **8 p.m. Eastern on Tuesday, October 21, 2014**.

Background information for this project can be found on the project page.

Instructions for Commenting

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

The drafting team will use this informal feedback to begin formal development of draft 5 of PRC-027-1 in November 2014. The standard will be posted for a formal comment period and ballot in December 2014.

Standards Development Process

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Individual or group. (36 Responses)
Name (21 Responses)
Organization (21 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
Question 1 (32 Responses)
Question 1 Comments (33 Responses)
Question 2 (32 Responses)
Question 2 Comments (33 Responses)
Question 3 (11 Responses)
Question 3 Comments (33 Responses)
Question 4 (30 Responses)
Question 4 Comments (33 Responses)
Question 5 (30 Responses)
Question 5 Comments (33 Responses)
Question 6 Comments (33 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
What is meant by “condition based”? Condition-based (referred to in Part 1.3) should be clarified in the Rationale Box for Requirement R1. It is implicit in requirement R1 that setting development is implicit in the process. The Drafting Team should consider deleting Part 1.5. It is addressed in Part 1.2. A Part should be added to address the implementation of the coordinated settings to Protection System equipment. There is no need for a quality or review process in this standard. As per Paragraph 81, the “how” is not necessary. It is the responsibility of the engineering or technical staff to implement their in-house process.
Yes
A Protection System misoperation should be a trigger. Our comment response to Question 2 suggested that possibly a Part be added. An addition or change to the interconnecting Elements can be used as a minimum trigger.
No
Parts 2.1 through 2.3 address interconnections. FERC was concerned with the standard not addressing the coordination of Protection Systems within a Transmission Owner’s footprint, referred to as “internal” or “intra-entity” Protection Systems. A Part (or Parts) must be added to specifically address that concern. Wording still needs to be added to capture FERC staff’s intent. The technical justification for selecting the 200kV threshold in Part 2.1 needs to be provided.
Yes
A definition for “coordination” should be developed to eliminate some of the variations in Protection System design philosophies. The language in Introduction Section 4. Applicability sub-Part 4.2.1 creates a potential hole in Protection System coordination. In some applications, Protection Systems are installed for the purpose of detecting Faults on non-BES Elements but may impact the BES if they are incorrectly set. For example, a radial delivery point tapped off a BES transmission line may have a blocking relay installed that does not appropriately detect faults in its designated zone of protection, causing the transmission line terminals to trip impacting the BES. Suggest that the wording of 4.2.1 be revised to read: 4.2.1 Protection Systems installed for the purpose of detecting Faults on BES Elements, and isolating those faulted Elements, and including those Protection Systems that if improperly coordinated could result in BES Element tripping. The Purpose of PRC-001-1.1 is “To ensure system protection is coordinated among operating entities.” The Purpose of PRC-027-1 is “To maintain the coordination of Protection Systems installed for the purpose of

detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection System components operate in the intended sequence during Faults." The industry definition of coordination is "Coordination of protective devices is the determination of graded settings to achieve selectivity." "Selectivity in a protective system refers to the overall design of protective strategy wherein only those protective devices closest to a fault will operate to remove the faulted component…". Protection System coordination achieves selectivity, not only with interconnections, but within a Transmission Owner's footprint. PRC-001-1.1 already addresses what PRC-027-1 is addressing. Efforts should be directed at improving PRC-001-1.1 rather than producing a new standard.
Individual
Barbara Kedrowski
Wisconsin Electric Power Co
No
While a process is needed to do this work, I don't think requiring a process should be part of the standard. At the end of the process there needs to be documented evidence that the Protection Systems are coordinated (as stated in R2). I think that the standard should focus on the final product, not require a process to get there.
No
: I don't see "develop Protection System settings" between 1.1 and 1.2, but perhaps it is implied. Part 1.5 should be done while developing the settings rather than at the end so if they don't coordinate you have to start all over again. However, this would require getting the neighboring entities related settings (part of 1.4) prior to developing your own settings. We would have a different sequence for coordination, so as stated in question 1, this shouldn't be part of the standard. Part 1.3 seems misplaced as it is when a review is required; this would be needed as part of the standard.
Replacement of protection elements other than like in kind replacements for failures.
No
Along with the definition for Interconnected Element, the Elements listed in parts 2.1 through 2.3 seem unclear. The way I read it if a line connects two Registered Entities, then only the Protection Systems for that line need to be coordinated. I don't think that is what the drafting team intends.
No
As stated in question 1, I don't think developing a process should be part of a standard.
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
No
- For 1.2, rather than a review process of the protection system settings, is it the intent to have a process to review the protection system coordination, or a process to review the development of the protection settings? - Similar for 1.3, the trigger should be for a protection system coordination review? - For 1.4, should it include a procedure to communicate any identified coordination issues on the interconnecting elements with other entities?
It may need very careful considerations to define this trigger; otherwise entities may end up wasting lots of precious resources on doing this review.
No
It is not clear exactly what coordination documentation is required. It is inherent that protection systems at both ends of the interconnecting elements would need to work together properly, but there is no "coordination" required between the protection systems at both ends of the interconnecting elements. Is the intent to require the protection systems on the BES elements adjacent to the interconnecting elements coordinate with that of the interconnecting elements themselves?

Yes
- This version of the standard applies to all BES elements; which is a big shift of direction from previous versions where it applies to the interconnecting elements only. The SDT should take careful pre-cautions that this new standard will not create unnecessary burden for protection system owners. - The title of the standard is confusing. Consider changing to: “Protection System Coordination During Faults”?
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration LP (“ICLP”) does not see the overriding need to completely overhaul PRC-027-1 just to account for transmission links internal to the TO’s network. In general, the process – which was nearing industry’s approval – will suffice provided those links are limited to a reasonable subset of substation-to-substation connections. In our view, this may require further vetting to properly identify the affected components, but the general concept should not change. It does not make sense to throw away several years of work without taking this step first.
Yes
ICLP does not disagree with the elements of coordination captured in R1.1 through R1.5, but is concerned that the lack of specificity in the criteria could become a major issue. It has been our experience that determinations seemingly left completely to Registered Entities, in this case the TO, GO, and DP; will be overridden by CEAs wherever binding language is not used in the standard (e.g.; in the requirement). This inevitably leads to an uneven assessment of compliance by audit teams – which is in conflict with the fundamental concept of continent-wide standards.
In Draft 4 of PRC-027-1, the industry reached near-consensus that a 10% change in Fault current across an interconnecting bus was the proper trigger. Consistent with our response to Question 1, if the scope of the standard is expanded to only include a subset of substation-to-substation located within the TO’s footprint, that triggering criteria does not need to change. It seems to us that it only becomes an issue if other parameters other than Fault current are considered – which extends beyond the concern expressed by FERC staff.
No
On the whole, ICLP agrees that the 60 month baseline should apply to a limited subset of Interconnecting Elements. However, we do not understand why generator interconnections to the transmission system are not limited to those operating at 200 kV and above – just like the corresponding connections between adjacent TOs are. This would be consistent with other standards – FAC-003-3 comes immediately to mind – who also have focused their efforts on the most critical transmission systems.
No
ICLP believes the Measures are directionally correct, but cannot provide our viewpoint one way or another when the requirements are so undefined.
ICLP was comfortable that the previous drafts of PRC-027-1 clearly identified those relay systems that react to a Fault. However, this latest draft is written at a much higher level – which makes no distinction between relay schemes which may appear to react to a Fault, but are actually triggered by secondary conditions resulting from one. For example, a Generator Owner has many relays that monitor voltage, frequency, and ground current which may damage equipment if action is not taken to isolate it. Based on our reading of PRC-027-1, it may require us to take steps to limit Fault-related transients or adjust relay ride-through thresholds wherever dynamic studies show a risk – even though accurate simulations of such phenomena are difficult to achieve. If this is not the intent, the drafting team may have to provide a list of applicable relays and a list of exclusions. This is the same issue that the development team for the Definition of RAS is addressing – and is not an easy determination. A better solution would be to re-use some of the language deleted from PRC-027-1 Draft 4, which is accurately focused on Fault coordination.
Individual
Jonathan Meyer

Idaho Power
Yes
Yes
Yes
A time based interval should be the default, perhaps every five years. Additionally, system topology changes in the vicinity of existing schemes, e.g. two buses, would trigger a recheck of a protection systems.
Yes
Yes
Individual
David Jendras
Ameren
Individual
Jonathan Appelbaum
The United Illuminating Company
Yes
Yes
Triggers should include additions or removals of system elements electrically adjacent to existing elements, system misoperations and increases in short circuit levels similar to those proposed in the earlier version of this standard. Decreases in short circuit current are problematic because a system coordination must include maximum short circuit levels but must also allow for generators and other sources to be off line which means the minimum fault currents under normal conditions can be substantially less on an operational basis.
R2.3 applies to “any monitored Facility of an [IROL] while R2.1 and R2.2 apply to Elements. If there is a distinction between monitored Facility and Element it should be specifically clarified. If not, then R2.1, R2.2 and R2.3 should all use the glossary term to either Elements or Facilities consistently.
Yes
Coordination of protection of a single element such as prescribed in section R2 will involve the protections of other electrically adjacent and possibly non-adjacent elements. This cascading effect will be difficult to define may extend far beyond the prescribed Elements and could ultimately involve most of the BES. How will the limits of compliance with this standard be defined. This could also result in a burdensome amount of effort and documentation.
Individual
Gul Khan
Oncor Electric Delivery LLC
Yes
No
This question is really two questions that Oncor answers No (Do you agree that Parts 1.1 through 1.5 of Requirement R1 are essential) and No (“Are there others that should be included”) Oncor believes that Part 1.5 should be modified to read; “A procedure to verify any identified coordination issue(s) for all Interconnecting Elements associated with proposed Protection System settings are addressed prior to implementation.” Part 1.5 should not be applicable for an “internal” or “Intra –

entity" processes. Part 1.2 in its "quality assurance or review process" should take care of the requirement for resolving coordination issues prior to implementation of Protection System settings for all "internal" or "intra-entity" Protection System settings.
Yes
Oncor believes that the present Requirement R1 part 1.3 is sufficient ("A set of minimum triggers to prompt a review of existing Protection System settings. Specified triggers may be time-based, condition-based, or a combination of the two"). Adding a list of minimum trigger(s) to Requirement R1 Part 1.3 would imply that an entity does not have the freedom to choose triggers that are not found in the set of minimum triggers of Part 1.3. Therefore Oncor proposes to add these triggers within a "Rational" box.
Yes
Yes
Individual
Andrew Pusztai
American Transmission Company LLC
Yes
ATC has no comments.
No
While Parts 1.1 through 1.5 contain elements of what is needed for a successful protective relay setting practice, as proposed, Parts 1.1 through 1.5 appear to pose a heavy administrative burden on the company required to implement its processes. In particular, R1.5 appears particularly impractical. ATC sees very little benefit in a separate process, given that a fundamentally sound setting process should prevent implementation of improper settings. Adding a separate administrative regulatory burden to meet this requirement misdirects resources from higher value tasks. Furthermore, the term "identified coordination issues" is subject to interpretation and needs to be better defined in the standard (R1.4 and 1.5). Finally, ATC suggests clarifying what is expected of the "quality assurance or review process," which would currently be performed in R1.2.
ATC suggests the following triggers: 1) a risk-based trigger based on the company's own installed equipment whereby the company knows which relays are more likely to misoperate; 2) a trigger that evaluates misoperations of similar technologies. If the criteria is too prescriptive, opportunities may be lost to address the most impactful to reliability.
Yes
ATC has no comments.
No
Measure 1 states that, "acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has implemented its process to coordinate its Protection Systems…" As written, the measure is very broad and has the potential to generate a large volume of evidence open to various interpretations of regulators.
The process outlined in Requirement 1, Parts 1.1 through 1.5, exhibits characteristics of industry best practices, such as those developed by industry forums and trade groups. ATC recommends that industry best practices continue to be handled outside the NERC Reliability Standards as they have been previously. Placing them in a regulatory framework will lead to inefficiencies due to administrative burden and lead to slower improvement in reliability.
Individual
Thomas Foltz
American Electric Power
No
AEP believes that R1 should be limited to the establishment of a process to coordinate BES Protection Systems, rather than the implementation of a process. M1 indicates that registered entities will be required to provide records to demonstrate the application of the developed process

for all BES Elements. A robust coordination process should be focused on ensuring that Protection Systems are set to operate in the intended sequence, rather than on producing documentation that adheres to a reportable format that can be easily understood by all. Registered Entities should be required to establish a coordination process and be trusted to follow the process. This would allow relay engineers to focus their time on ensuring proper coordination rather than preparing documentation. We believe the evidence described in M1 would be acceptable if it was to apply only to Interconnecting Elements. Additionally, AEP has concerns regarding how R1 will be audited and believes that as currently written, that it may be too subjective and open to auditor interpretation. For example, how does one determine what constitutes a quality assurance process? How much latitude would an auditor have to deem the entity's process inadequate and subsequently issue a potential violation of R1 based on Parts 1.1 through 1.5? NERC Standard PRC-005-1 uses a similar approach, requiring entities to "have a Protection System maintenance and testing program" and to implement it. AEP urges the drafting team to consider the difficulties industry has had with PRC-005-1 R1 when drafting PRC-027.
No
While we agree what that these may be essential elements of a successful coordination process, we don't agree that such elements should be within the scope of an audit as their application can be subjective and open to auditor interpretation.
Yes
AEP does not believe that the standard should prescribe a specific set of minimum triggers for all Registered Entities to follow. Entities should be provided the flexibility to define within their process what should prompt a new coordination study. Rather than using the phrase "minimum trigger", AEP believes it would be more appropriate for R1.3 to refer to a defined methodology that includes conditions for performing coordination studies. For example, "A defined methodology to identify what system conditions should prompt a new coordination study". A potential condition described within this methodology could include when settings are reviewed due to a system change (line, transformer, generator). In these cases, coordination in a given area would be reviewed outwardly from the system change until it is determined that no additional settings changes are needed to achieve coordination. AEP believes that this proposed methodology would be adequate to identify changes to system conditions and perform coordination as needed.
No
As stated in our response to Question #1, AEP believes that R1 should be limited to the establishment of a process to coordinate BES Protection Systems, rather than the implementation of a process. M1 indicates that registered entities will be required to provide records to demonstrate the application of the developed process for all BES Elements. A robust coordination process should be focused on ensuring that Protection Systems are set to operate in the intended sequence, rather than on producing documentation that adheres to a reportable format that can be easily understood by all. Registered Entities should be required to establish a coordination process and be trusted to follow the process. This would allow relay engineers to focus their time on ensuring proper coordination rather than preparing documentation. We believe the evidence described in M1 would be acceptable if it was to apply only to Interconnecting Elements.
There are some situations where performing a coordination study does not need to be performed because it does not provide any technical value. The draft should be revised to allow Registered Entities to technically justify why a coordination study does not need to be performed. The previous draft allowed for this, but has been removed. There will be times when a relay setting is found to be incorrect for various reasons. The discovery of such a condition might be due to a Protection System Misoperation. PRC-004-2 allows entities to identify such conditions and take corrective actions as necessary to resolve the relay setting issue. Since in these cases the relay did not operate in the intended sequence, would this become a reportable violation of PRC-027? AEP believes that to best promote reliability of the BES, entities should retain the ability to identify and correct settings issues as they are found without the need to report a violation of a Reliability Standard.
Group
Puget Sound Energy
Dianne Gordon
Yes

Yes
Yes
Yes
Yes
Individual
Chris Scanlon
Exelon Companies
No
We believe that R1 is overly burdensome from a compliance perspective and is not necessary to reach an adequate level of reliability for the BES. Creating a new process and procedure does not add much value and further evaluating compliance with this requirement will be very subjective. Instead SDT could identify the requirements and ask compliance with the same. Changing R1 as below would provide for an adequate level of reliability without creating a lot of unnecessary compliance work. In current draft, propose that the word "implement" in R1 be changed to "have". M1 would accordingly be changed so that the entity could produce the appropriate process documents as evidence for R1. No other evidence would be required.
No
The word "essential" in this statement conveys a weight that is not justified and may lead to complex and unwieldy processes where simple ones will suffice. This is a standard that addresses a problem that has not, in practice, been a problem. I agree these are elements of a successful coordination process, but they create an extreme burden of documentation when simple communications between peers is all that is really needed. We do not believe that triggers are needed to assure protection system coordination. We do not use triggers in any procedures or processes we currently have that prompt a coordination review. Misoperations on our system are essentially non-existent and have been for decades. Thus we propose that the drafting team remove R1.3 as it is not necessary to provide an adequate level of reliability for the BES. The SDT should rather simply require of the Generation owner that any time protection system settings are changed, that needs to be coordinated with TO. This process and procedure requirement with triggers is burdensome and complicated for GOs.
No
The bulk of coordination changes are condition based; they will be required by the addition or reconfiguration of BES facilities or changes to protection systems. Coordination changes required by an increase in fault current levels will almost always be identified in the process of reviewing coordination for the change to BES facilities. Requiring a burdensome process to periodically review and document fault current based triggers adds very little value and adds a layer of unneeded complexity, which can ultimately detract from the goal of creating a more secure protection system. Based on our experience operating a large power system, we do not believe that triggers are necessary to assure coordination and an adequate level of reliability for the BES. We encourage the drafting team to re-think the need for codified triggers to prompt coordination reviews. We believe that selection of triggers should be by the registered entities, based on their own experience and engineering practices, and not designated by the compliance authority. Appropriate triggers might include the addition of a new transmission line (200kV or higher), a new generator (1000 MVA or higher), or a new autotransformer (1000 MVA or higher), change of XFMRS (MPT, UAT and SAT) or Generator or change in any of their parameters.
Yes
We have no suggestions for adding additional circuits. It is our understanding that these R2.1, R2.2, and R2.3 circuits are the only circuits required to be reviewed to meet this standard and we agree with the drafting teams decision. Review of other circuits is necessary to provide an adequate level of reliability. Thus, we suggest that the drafting team clearly reflect this in the Facilities section of

the standard. Specifically 4.2.1 could be changed to read “Protection Systems installed for the purpose of detecting and isolating Faults on the following BES elements; list those specified in R2.1, R2.2, and R2.3. Exelon GO’s question does this include protection for Generator, MPT or SAT in addition to the connecting leads between switchyards and GO owned transformers or just the connecting leads?
No
See Q 1. M1 would accordingly be changed so that the entity could produce the appropriate process documents as evidence for R1. No other evidence would be required.
This is an example of an extremely burdensome standard when there are really very few misoperations that are caused by miscoordination of protection on interconnecting facilities. To make the standard and implementation easier for the GO, SDT needs to identify the specific GO owned relays which should be coordinated with TO. For example distance relays, overcurrent relays; negative sequence relays etc. do require coordination while differential, reverse power, Generator ground etc. do not require any coordination. Same should be done for the TOs relays which require review by the GO.
Group
ACES Standards Collaborators
Jason Marshall
Yes
We are intrigued by this new approach and cautiously optimistic that this approach is an improvement over previous drafts that contained very detailed performance requirements and numerous administrative requirements. While this new approach does appear, in essence, to expand the reach of the standard to all BES Protection Systems from just those Protection Systems for Interconnecting Elements, we believe requiring a process document is a better approach. This is especially true since the performance aspects will be limited to Interconnecting Elements that are 200 kV and above or that are connected to generator(s) with 75 MVA capability and Facilities that are part of an IROL per R2.
No
(1) Overall, we agree with these Elements, but believe that the SDT should provide additional clarifications for small entities. For example, since R1 applies to TOs, GOs, and DPs, can a small entity, such as a small G&T cooperative, have a single process document? If so, the SDT needs to modify Part 1.4 to be clear that it would only apply to communication and coordination with other Registered Entities and not other functional entities assigned to the same Registered Entity. In essence, Part 1.1 would cover “Interconnecting Elements” between the small G&T’s different functional entities , which would make more sense, particularly in cases where there is a single protection engineer. In this situation, how would the protection engineer document their self-communication per Part 1.4? (2) Implementation of Part 1.2 could be a challenge for small entities, especially small distribution cooperatives that own transmission Protection Systems and likely have a single protection engineer. Some guidance on expectations in the quality assurance or review process for these entities would be helpful since they likely cannot implement a peer or supervisory review.
One obvious trigger would be a Misoperation; however, this trigger would need to be coordinated with PRC-004 to avoid overlaps in the standards. Other triggers would include: system topology changes impacting the impedance (a threshold could be set) seen by the Protection System, generation additions, expansions, or retirements.
No
While we do not have an issue with focusing compliance monitoring on the specified Elements identified in R2, we do believe the requirement in its current form meets Paragraph 81 criteria. A Paragraph 81 criterion states that a requirement should be retired if it only compels production of documentation. Since R1 already compels coordination, R2 is would appear to be a documentation requirement that should be struck. The reason documentation became a Paragraph 81 criterion is because documentation is required to demonstrate compliance with other requirements. Furthermore, NERC can compel the production of the documentation via other processes such as compliance monitoring (e.g. audits, spot checks), section 1600 data requests, or possibly even include these specified Elements in the RSAW as part of the data sampling process. Since FERC

ultimately approved these Paragraph 81 criteria when they approved the retirement of the requirements meeting the criteria, we cannot see how R2 should remain in its current form as it is not consistent with a prior Commission order.
No
(1) We are concerned that M1 could cause an auditor to believe that they need to review evidence for every single Protection System setting since it states that the responsible entity must have evidence of implementation. We need to avoid this burdensome compliance approach to be consistent with the RAI. We suggest that the drafting team should work with NERC compliance staff during the development of the RSAW to be clear that a sampling approach will be used. (2) We believe that the M2 is too vague. What kind of records is being asked for? For example, would output from a software package such as Aspen be the desired evidence?
(1) We believe that the main requirement for R1 should ask for a plan rather than a process and that Parts 1.4 and 1.5 should ask for processes. Since setting relays occurs in the operations planning horizon, use of plan and procedure may not technically fit the category of an Operating Plan and Operating Process, as defined in the NERC glossary; however, use of plan and process, as described above, would be consistent with the definitions and may avoid some confusion. It may even make sense to use the defined terms. (2) Since R2 is intended to be an “one-time performance requirement necessary to establish a baseline of coordination”, will this requirement be retired after the baseline is established? We believe it should be. (3) Will a Protection System Misoperation indicate that a violation of R1 has occurred? We would suggest that should not be the case, but an auditor could interpret such a Misoperation as an indication that the Protection Systems did not operate in the “intended sequence during” a Fault. The drafting team should be careful to avoid a Misoperation automatically indicating a violation because it will discourage reporting of Misoperations and the lessons learned entities share with the rest of industry.
Individual
Michael Moltane
ITC
Yes
No
1.5 is not essential because it is part of 1.4 process of seeking concurrence from the other entity. Calling this one aspect out specifically provides no reliability benefit and only increases administrative compliance burden to track dates, etc.
No
We agree the chosen Elements are more critical than others. However we suggest removing this requirement as there is no evidence of widespread miscoordination, per SDT in previous drafts of this standard.
No
M2 needs to include evidence of coordination from prior to effective date of the standard.
Group
Dominion
Connie Lowe
Yes
Yes
Yes
The SDT needs to explain the basis for selecting the 200kV threshold in Part 2.1.
Yes

Dominion is concerned about a potential hole in Protection Coordination created by the language in section 4.2.1. In some circumstances, Protection Systems are installed for the purpose of detecting Faults on non-BES Elements but may impact the BES if they are incorrectly set. For example, a radial delivery point tapped on a transmission line may have a carrier blocking relay installed that does not appropriately detect faults in its designated zone of protection, causing the transmission line terminals to trip, impacting the BES. Dominion believes the language should be modified to include Protection Systems that, if improperly coordinated, could result in a BES Element tripping.
Individual
John Merrell
Tacoma Power
Yes
Tacoma Power agrees with the concept of requiring a process to address the coordination of Protection Systems. However, great caution must be exercised that entities and their ratepayers are not overly burdened for marginal reliability gains. While having such a mandatory and enforceable standard may create additional incentive for entities to periodically review Protection System coordination, mandatory and enforceable standards risk significant administrative cost if not carefully crafted.
No
It is not completely clear what Part 1.1 is trying to achieve. Is this part intended primarily to refer to short circuit models? If so, this should be more clearly stated.
Because this will be a mandatory and enforceable standard, the triggers should be clear and pose minimal burden to entities to monitor even if the triggers do not comprise an all inclusive set. The following four triggers are suggested: -The 3LG or 1LG fault current at the bus to which the protected equipment connects has changed by some percentage (e.g., 10%) relative to a baseline. This approach was proposed in previous drafts of PRC-027-1. This trigger is intended primarily to maintain coordination over time as the power system evolves, resulting in incremental changes that can have a potentially significant cumulative effect. (One possible issue with this trigger is that Generator Owners may not have immediate access to this information and would therefore be dependent on their Transmission Owner to trigger the review.) -An alternative to this trigger could be a time-based trigger. The interval should be no shorter than once every five calendar years, and a ten calendar year interval may be more reasonable. Tacoma Power maintains that an entity should be permitted to choose between a time-based trigger and a trigger based upon changes in Fault current (or a comparable trigger) and that en entity should be able to make this choice either globally or per Protection System (or protected Element). -There is a change in the impedance or topology of a protected element. For example, a line is segmented, a transformer is replaced, or a new power system Element is installed. In general, assessing coordination would go one zone back to include remote backup protection. -There is a material change to a Protection System. This trigger would include cases in which (1) the power system is not changing but a Protection System is or (2) the power system is changing elsewhere and cascading Protection System changes are required. Example of (1): An entity is modifying their protection philosophy. Example of (2): A segmented line resulted in changes one zone back, which resulted in a review of the backup protection one zone further back; if changes are needed, a review may be needed even one zone further back.
No
It seems that Requirement R2 may raise some of the same concerns that FERC staff expressed previously. That is, FERC may expect that baseline documentation of coordination of all Protection Systems applicable to PRC-027-1 be established. This may be true particularly if a trigger will be established based upon a change in bus Fault current. Requiring initial documentation of coordination would have a comparable burden as a time-based trigger. If Requirement R2 is expanded, and if a condition-based trigger is selected that looks at some parameter like bus Fault current, then an entity should only have to monitor for that condition after Requirement R2 has been satisfied in whole. It should also be noted that, if Requirement R2 is expanded, implementation of Requirement R2 could result in some miscoordination during a transition period because it will not be practical to review and change all Protection Systems at once; therefore, there could be a period of elevated risk to the BES. If the drafting team elects to limit Requirement R2 to Interconnecting

Elements, then Part 2.2 seems out of place when one entity may be both the Transmission Owner and Generator Owner and one group is responsible for all of the Protection Systems involved.
Yes
As the drafting team is aware, Protection System coordination will not be maintained under all contingencies (of power system Elements or Protection Systems components). Sensitivity to contingencies will depend upon multiple factors including Protection System philosophy and vintage of Protection System components. This issue should be acknowledged in some form, either within this standard or within application guidelines. Tacoma Power suggests that “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements” be changed to “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements from the BES.” In other words, add “from the BES” at the end. Some Protection Systems installed for the purpose of detecting Faults on the BES may trip non-BES elements as well (e.g., non-BES generation connected to a tap on a transmission line). These portions of the Protection System should be excluded. The drafting team has taken great care to acknowledge that different entities have different philosophies. Tacoma Power does not proposed that Protection System coordination philosophies be included in PRC-027-1, but the lack of standardization of Protection System philosophies may make coordination more difficult to achieve in some cases. Standards like PRC-023 and PRC-025 have taken bold steps to settle philosophical differences among some protection and operations personnel. Might this level of standardization ultimately be needed to help entities coordinate Protection Systems associated with Interconnecting Elements? The NERC definition of Fault is “an event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.” It is Tacoma Power’s understanding that the purpose of PRC-027-1 is primarily, if not exclusively, to maintain coordination during short circuits. Broken wires (when there is no accompanying short circuit) and intermittent connections are generally not the subject of coordination studies. Furthermore, coordination during high-impedance Faults, especially during contingency conditions, may not always be possible/practical. Tacoma Power requests that the purpose of the standard be restricted to short circuits, even if this is acknowledged in application guidelines. Alternatively, the definition of Fault could be revised as part of this project. Regarding Requirement R1, some allowance should be acknowledged, perhaps in application guidelines, that an entity may include in its process a mechanism to identify de minimus impacts, which could result in a variance to, or waiver of, the process. The goal is reliability. The drafting team should be applauded for its patience through all of these drafts. It is unfortunate that FERC’s concern was identified after four drafts were balloted, even though none of the earlier drafts addressed “internal” or “intra-entity” coordination.
Group
Tennessee Valley Authority
Brandy Spraker
Group
SERC PCS
David Greene
Yes
Yes
Requirement 1.5 seems unnecessary because the process of coordinating settings is not complete until all issues are resolved.
The list of triggers needs to be concise and it needs to be communicated that an entity’s process will not need to include all triggers. Reasonable triggers are: change in fault current, removal or addition of elements to a station/bus, line reconductoring, or time based per the entity’s specification.
Yes
R2 and its subparts 2.1, 2.2, 2.3 provide a clear and acceptable scope of facilities covered by this standard. Requirement R1 aligns with how industry typically performs Protection System coordination. The statement made in the Background section above: “The primary concern was that the proposed standard did not address the coordination of Protection Systems within a Transmission Owner’s footprint, referred to as “internal” or “intra-entity” Protection Systems” appears to propose

greatly increasing scope of facilities to possibly be covered by this standard. We support the scope of facilities as currently stated in R2, but would not agree with increasing the scope of facilities within R2 as we believe them to be adequately addressed within the process for R1.
Yes
The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Amy Casuscelli
Xcel Energy
Yes
R1.1 is very ambiguous and appears to say that a method to updata "data" is needed for compliance. This is a very ineffective stipulation as it is on the surface very menial (i.e. data collection?). A more useful stipulation might be to have a methodology concerning how the settings should be developed, and what guidelines are used during the coordination analysis. We agree that is it an improvement from the prior version in that the entity can design their coordination process to meet the requirements.
Yes
R1.5 is vague with the use of the phrase "any identified coordination issues." This could be interpreted many different ways depending on the different relay philosophies and methods between TO's, GO's and DP's. What is an "identified coordination issue" to one TO, may not be a "coordination issue" for another TO. See suggested language in our response to question 6.
Yes
It is not clear. Will the requirement change to include the soon to be identified triggers? or is the generic criteria (time, condition) going to remain?
No
The 60 months portion of the requirement seems to be something that should be addressed in the Implementation Plan of the standard, and not stated (repeated) in the requirements section. The requirement should be modified to just state that the registered entities "...shall have documentation that..." Also see response to Question 6
Yes
We read M1 to mean that entities can determine what eveidence is required for coordination based on the self created processes created pursuant to R1 and R1.1-R1.3.
We believe that R1.4 & 1.5 don't belong within R1 since they relate specifically to Interconnecting Elements. We recommend a structuring similar to: R1, R1.1 -1.3 as currently proposed. R2 Each Transmission Owner, Generator Owner, and Distribution Provider with Interconnecting Elements: - associated with Transmision operated = > 200KV - associated with BES Generating resource(s) - Any monitored Facility of an Interconnection Reliability Operating Limit (IROL). shall develop and implement a process to coordinate Protection Systems of the Interconnecting Elements, to include, in addition to requirements stated in R1.1 through R1.3: R2.1 A procedure to communicate the Protection System settings with Transmission Owners, Generator Owners, and Distribution Providers associated with Interconnecting Elements and seek concurrence that there are no concerns with the proposed Protection System settings. R2.2 A procedure to resolve, prior to implmementation, with other entities of Interconnecting Elements any concerns associated proposed Protection System settings.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Yes

No
1. 1.3 Does one trigger such as ‘every x years’ meet the intent of a ‘set of minimum triggers’. 2. 1.4 ‘ ... there are no identified coordination issues...’ should read ‘ any identified coordination issues have been addressed (or resolved?)’. Since a needed change in settings may require other changes that will be accomplished after the fact. 3. However, some of the details appear to be duplicative. These include the following two items: 1) R1.1 vs R1.3 where 'method to review' of R1.1 and 'triggers to review' of R3.1 are the same detail; 2) R1.2 vs R1.4 vs R1.5 where 'QA or review process' of R1.2, 'communicate settings and seek concurrence' of R1.4, and 'procedure to verify any identified coordination issues are addressed' of R1.5 all are essentially the same notion.
Yes
See response #1 to Q2. X years, y% change in fault current, change in system within z busses away, addition or retirement of generation within z busses away, etc
Yes
1. We agree with the element identified and believe it is appropriate for our system in that it will cover the intent of the Reliability of the BES. 2. With the scope of Transmission Owner Protection Systems specified by R2.1 being at and above 200kV, does it not follow that the GO Generating resources in the scope of R2.2 should also be limited to those connected at and above 200kV to align the Protection Systems to be compared in R1.4? 3. However, should there be a provision to capture more of the interconnections it the case that the system is comprised of all or a significanbt amount of <200-kV?
Yes
We agree with the present scope related to Interconnecting Elements and believe that there is a reliability benefit to this approach as has been reflected in our past affirmative votes on this Standard. We would not support the expansion of the applicability of R2 to include all elements of the BES nor the inclusion of lines internal to the entity other than those noted in R 2.3.
Group
Duke Energy
Colby Bellville
Yes
No
1.1.: No comment 1.2: Duke Energy suggests removing the phrase “quality assurance” from part 1.2 of Requirement 1. We feel that the idea of “quality assurance” is already inherent in the coordination of Protection Systems in or between entities. Also, “quality assurance” may be viewed as being too subjective to demonstrate compliance during an audit. 1.3: No comment (See question 3.) 1.4: We seek further clarification from the drafting team on part 1.4. Is this requirement already covered in PRC-001, and if so, will it be removed from PRC-001? It appears that if kept, there is potential for non-compliance of two requirements in two different standards. Also, we suggest replacing “procedure” with the term “method” to maintain consistency with part 1.1. 1.5: Duke Energy requests further explanation as to the intent of the drafting team for part 1.5. As currently written, it would be difficult to write a single procedure for numerous coordination issues that could arise. We suggest replacing “procedure” with the term “method”, for the reason mentioned above, as well as to maintain consistency with part 1.1.
Duke Energy prefers that the minimum triggers be Condition-based. We do not prefer Time-based triggers based on the possibility that no fault duties have changed since the last study. We feel that the triggers should be Condition-based, based on a certain percentage of change, if any changes have occurred.
No
Duke Energy asks for clarification from the drafting team on the selection of 75 MVA for subpart 2.2. A concern is that some individual dispersed generating resources operate above 75MVA, and are connected to 115kV. This would require the testing of those 115kV elements. We submit for the drafting team’s consideration, an increase of the 75 MVA level, or the insertion of a caveat to eliminate unnecessary testing. See the suggested language revision for 2.2 below. “Interconnecting

Elements associated with BES Generating resource(s) with gross plant/facility aggregate nameplate rating greater than 75 MVA if operated at 200kV or above. We feel this language revision reduces the likelihood of bringing in those individual dispersed generating resources that operate below the 200kV level.
Yes
Individual
Muhammed Ali
Hydro One
No
This concept is very confusing. The current wording in R1 requires the entity to carry out or implement a process then R 1.4 and R1.5 require procedures – so procedures within a process. Suggest wording change to “…. shall have a program in place to coordinate…” – that program could include procedures. Of course this has been happening in most places but this will create a huge documentation burden for entities
Yes
Notwithstanding our comments in Q1, these more or less would be necessary steps to ensure coordination. However we offer some comments: R1.1 This requirement is too generic. What does this requirement really mean? Needs more specificity – what kind of data? R1.2 We generally agree with the concept but for this standard should be limited to coordination only R1.3 Do these triggers prompt a review of the coordination across the entire entity’s system? Of course keeping track of all system changes that necessitate a coordination review will be a documentation nightmare for condition based triggers. R1.4 This sub-requirement has 2 actions – communicate the settings, then seek concurrence. Likely needs to be broken up into 2 sub-requirements. We assume this needs to take place initially then subsequently when a review is triggered?
We believe the triggers identified in earlier versions of this standard are adequate. However in line with comments in Q2, how wide of an area needs to be studied?
Yes
Yes
1. The purpose statement is confusing. Is the intention of the standard to assume protection systems are coordinated already and the standard is to “maintain” that co-ordination? 2. Also the wording in the purpose statement “such that the Protection System components operate in the intended sequence during Faults” is misleading. This implies some sort of coordination of the components of the individual protection system, implying the need for SOE etc. Suggest “…such that Composite Protection Systems between Elements operate in the intended sequence during Faults”. 3. Similar to PRC-023 and PRC-026 it will be helpful to have an appendix with the list of elements that will require coordination in this standard (based on the SPCS whitepaper). Previous versions of the standard referenced coordination of other non-fault protections would occur in other standards. Yet for instance there is no requirement in PRC-026 to coordinate out of step protections on adjacent Protection Systems. Otherwise too much latitude will be provided to an auditor.
Group
Pacific Gas & Electric Company
Aaron Feathers
Yes
No
We do not believe that Requirement 1.5 is essential since it is part of the process in Requirement 1.4. Requirement 1.4 could be modified to add "verify" to combine these two requirements. "1.4 A procedure to communicate the Protection System settings with Transmission Owners, Generator

Owners, and Distribution Providers associated with Interconnecting Elements and [verify] that there are no identified coordination issues."
A 10% or greater change in Fault current is an appropriate trigger. For a time based trigger, not less than 5 calendar years.
Yes
We agree with the chosen elements.
Yes
In general, we agree with the measures. A 5 calendar year interval is preferred over a 60 calendar month interval due to utility budgetary cycles for the funding to perform the routine coordination studies.
Group
PPL NERC Registered Affiliates
Stephen J. Berger
No
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. There is no apparent need for PRC-027-1. Its purpose, “To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection System components operate in the intended sequence during Faults,” appears to be just a subset of the PRC-001-2 purpose, which is, “To ensure system protection is coordinated among operating entities.” Some explicit duplications are also apparent - R1.1-1.3 of PRC-027-1 are already covered by PRC-019-1 regarding voltage regulating functions, the procedure called-for in R1.5 seems to be nothing more than R2 of PRC-001-2, and the settings of loadability relays are covered by PRC-023 and PRC-025. R1.4 appears to mandate that every Protection System setting implemented by a DP, GO or TO be communicated to all other DPs, GOs and TOs that the entity connects-to, which would create a burdensome flood potentially unnecessary information. Even if R1.4 communications were pared-back to information that the receiving party wants to know, the, “seek concurrence,” portion of R1.4 is too weak. Would sending an email that may never get answered be sufficient? R2 is even more unworkable, requiring coordination among entities without any direction on how this is to be accomplished. Such lack of clarity might not be a problem for vertically-integrated utilities, but in competitive markets there must be a lead entity. An uncooperative entity could otherwise cause all parties that it connects-to to incur a PRC-027 R2 violation. Project 2007-06 should be terminated and, if any gaps in coordination can be found, they should be addressed via updates to PRC-001, PRC-019, PRC-023 and/or PRC-025. In the event that NERC still wishes PRC-027 to proceed it should at least be made inapplicable to GOs, because the only sequence-of-tripping issue for such entities is that they ride-our disturbances until load-shedding schemes have been implemented, and this achievement is ensured by PRC-024.
No
See the response above to question #1.
No
See the response above to question #1.
No
See the response above to question #1.
Group
FirstENergy Corp
Richard Hoag
No

FirstEnergy agrees with the need for a reliability standard to ensure relay coordination on ties between different Transmission Owners, but does not agree that a reliability standard is needed for internal Transmission Owner coordination. Experience has shown that relay mis-coordination (i.e. relays tripping in the wrong sequence due to timing or pickup setting errors) has been the root cause of a misoperation far fewer times than other setting issues, such as directional element settings. However, FE believes that for the special case of relays that are owned by two different companies does warrant a reliability standard to ensure that the information necessary to perform relay settings coordination flows freely between the Transmission Owners involved.
No
FirstEnergy agrees that, in general, the items listed in Parts 1.1, 1.2 are elements of a successful coordination process. For Part 1.3 FirstEnergy supports the triggers developed previously for draft 4 of this standard. For Part 1.4 and Part 1.5, coordination may not be possible for extreme system conditions. Perhaps incorporating a statement such as “under reasonable contingency conditions” or pointing to contingencies studied as part of PRC-023 attachment B or that are part of TPL standards may be appropriate. Also, Part 1.5 includes the phrase “settings are addressed prior to implementation”. Clarification is requested on this statement. There can be cases where a large system upgrade (such as building a new substation) will require settings changes at many remote substations – most likely ground overcurrent backup settings. What most often happens is that some of these settings can be changed before the new substation goes into service, but in some cases applying settings intended to be used after the new substation is built would negatively affect the reliability of the BES during the time period prior to energization of the new substation. Is Part 1.5 referring to the calculation of settings? Or actual field implementation?
No
Since these triggers will have a large impact on the efforts required to comply with this standard, FirstEnergy supports using the triggers already vetted through the Standards process in draft 4 of this standard.
Yes
FirstEnergy agrees with the spirit of the requirement but believes the initial implementation is better described in an Implementation Plan rather than a one and done requirement. The standard should be clear on any initial requirements in an implementation plan and the requirements should clearly describe any ongoing expectation whether event driven or periodic update driven.
Yes
An implementation plan was not included with this draft. However, FirstEnergy believes that a period of time for entities to create, review and/or update the documents required in 1.1 and 1.2 should be established prior to enforcement action being taken for the other requirements of this standard. Suggest 12 to 18 months.
Individual
Glenn Hargrave
CPS Energy
No
Please keep this from going down the PRC-005-1 road, where many companies received fines because of poorly written procedures and inconsistent auditing methods and interpretations across regions as opposed to inadequate maintenance. We would be more supportive if the process were created as part of a regional process that was put upon the Planning Coordinators or Regional Entities to create/approve instead of each end user.
No
First, not sure what a quality assurance or review process is. Secondly, Part 1.4 will be problematic if different entities have specific communication procedures for seeking concurrence. Finally, Part 1.5 addresses proposed settings, but what about existing settings.
A trigger should be a change in the impedance or ratings of elements connected to interconnecting busses. However, this change should be set to a percent change not just any minor change (e.g. re-route of a couple of towers). Also, if relevant elements of protection systems located at the interconnected busses are modified, then this could trigger a review as well.

Yes
No
M1 is too open for interpretation.
Individual
Manon Paquet
Hydro-Quebec Production
Yes
Coordination of all Protection Systems (not just BES Protection Systems) is fundamental for the design and operation of power systems. It's also a good practice to have a process to describe the coordination methodology. Do we really need a standard to obligate the industry to implement a process?
Yes
There could be different un-formal ways to communicate coordination issues with other entity associated with Interconnected Elements
Protection misoperations, modification of the protected Elements, modification of the short-circuit level
Yes
Documentation, database or acceptable evidence demonstrating that the Protection Systems for the specified Elements in Parts 2.1 through 2.3 are coordinated.
Yes
We agree with the principle of "Acceptable evidence"
Individual
Patricia Robertson
BC Hydro
Yes
Yes
BES configuration change, Mis-operation
Yes
Yes
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
Some trigger points to consider: - Significant (~10%) change short-circuit fault currents (this is what the previous draft version included). - Addition of new generation. - Increase of transmission capacity (new lines and/or transformers). - Introduction new zero-sequence sources (certain types of transformer connections). - Change in the protection scheme.
Yes

Yes
Group
Bonneville Power Administration
Andrea Jessup
No
The stated purpose for earlier drafts of this standard was as follows: “To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.” In this latest draft, the scope and purpose of the standard have been greatly increased to include “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements.” This change from Interconnected Elements to all BES Elements represents a broad increase in regulatory scrutiny to an area where BPA feels it provides little to no increase in system reliability. BPA is aware of no evidence to indicating that widespread mis-coordination of BES Protection Systems is a problem which is in need of a regulatory attention. BPA would prefer that the intent of this standard remain the regulation of information exchange between Functional Entities. BPA proposes R1 be removed from the standard.
No
BPA notes that numerous industry guides, white papers, text books and professional development courses have been devoted to the subject of successful relay coordination. BPA believes it is beyond the scope of this standard to delineate the essential elements of a successful coordination process. BPA would prefer that the intent of this standard remain the regulation of information exchange between Functional Entities. BPA proposes R1 be removed from the standard.
BPA believes Functional Entities must be left to apply their own engineering judgment and resources when developing reasonable triggers for the review of relay settings. BPA does not support a NERC standard to define time, system event, or conditional triggers which all of the industry must follow. To do so will certainly increase the number of unnecessary violation most of which will be of an administrative nature. Take for example the installation of a large transformer at a single substation. Without a doubt settings in the area will require review but how many busses or lines should be involved in this review, to what extent should a wide area coordination study be conducted, can this review wait until the next periodic settings review? Many of these questions are based on engineering judgment and knowledge of the local system which may differ from what is prescribed by the drafting team. BPA would prefer that the intent of this standard remain the regulation of information exchange between Functional Entities. BPA proposes R1 be removed from the standard. If R1 is not removed, BPA suggests at least the development of triggers for settings review must be left to the Functional Entities.
No
The delineation of the 60 calendar months time frame presumes that all Functional Entities will have adopted at a minimum a 5 year time-based review trigger for Protection System settings. As stated earlier, BPA is opposed to the drafting team’s development of a set of minimum triggers. Therefore, BPA proposes that the wording be changed as follows: Each Functional Entity shall document the exchange of information sufficient to coordinate Protection Systems on Interconnecting Elements which meet the BES definition whenever the following conditions are met: 2.1 New Protection System installation. 2.2 Significant change to an existing Protection Systems or its settings. 2.3 Information is requested by a Functional Entity for the purpose of Protection System Coordination.
No
BPA proposes Measure M1 should be removed with all of Requirement 1. BPA suggests Measure M2 should be altered to reflect the recommended changes to R2: Acceptable Evidence includes but is not limited to, electronic or physical dated records demonstrating the exchange of information for changes or additions made to Protection Systems on Interconnecting Elements which meet the BES definition.
Individual
John Brockhan

CenterPoint Energy
Yes
CenterPoint Energy appreciates FERC’s concerns on coordination of Protection Systems within a Transmission Owner’s footprint, even though it appears protection coordination issues have not been a major factor in events reported through NERC’s Event Analysis program, nor a predominate root cause of reported Misoperations collected for Reliability Standard PRC-004. The preliminary draft of Requirement R1 for Draft 5 of PRC-027-1 appears to be a reasonable and logical approach to establishing a mandatory requirement to address coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements. CenterPoint Energy believes such an approach recognizes several things: the majority of existing Protection Systems have time-proven and fault-proven Protection System set points; entities do have existing processes for protection coordination and have been performing protection coordination studies; and, this will bring in a very large number of Protection Systems into the mandatory scope for coordination, especially on 100 – 200 kV systems. Furthermore, the approach utilizing “triggers” allows coordination of these Protection Systems to be phased-in more gradually and as needed.
No
(1) CenterPoint Energy recommends deleting Requirement R1.2 from the standard as we do not agree that a quality assurance or review process is an essential element for a successful protection coordination process. We expect that there are numerous, existing coordination set points that were successfully established without such a process. CenterPoint Energy is also concerned that the use of “Protection System settings” in Requirement R1.2 is overly broad and could be interpreted to include protection settings not associated with a protection coordination study. (2) If Requirement R1.2 is not deleted, CenterPoint Energy recommends clarifying “Protection System settings” as used in Requirement R1.2. The proposed wording for Requirement R1.2 states: “A quality assurance or review process of the Protection System settings.” CenterPoint Energy recommends rewording Requirement R1.2 as the following: “A quality assurance or review process of the Protection System [coordination study].” (3) In addition, CenterPoint Energy recommends clarifying Requirement R1.5 which currently states: “A procedure to verify any identified coordination issue(s) associated with proposed Protection System settings are addressed prior to implementation.” Requirement R1.5 appears to be related to Requirement R1.4 that provides for communication between entities on Interconnecting Elements. CenterPoint Energy suggests the following wording for Requirement R1.5: “A procedure to verify any identified coordination issue(s) associated with proposed Protection System [set points] [for Interconnected Elements] are addressed prior to implementation.”
Yes
CenterPoint Energy agrees with the chosen Elements in Parts 2.1 through 2.3 and does not have any suggestions for additional Elements to include in Requirement R2.
No
Measure M2 uses the term “Responsible Entity” which is not defined in the proposed standard or in the NERC Glossary of Terms Used in NERC Reliability Standards. As this standard uses Functional Entities in the Applicability section, CenterPoint Energy expects that “Responsible Entity” should be changed to lower case. In addition, Measure M2 appears to indicate that the documentation must be from protection coordination studies performed within the 60 months after the effective date of the standard. This does not allow for the use of documentation of protection coordination studies performed prior to the effective date. CenterPoint Energy recommends clarifying Measure M2 to allow previous protection coordination documentation, especially considering that there are presently many growth and reliability projects in progress. One way to provide clarity is to delete the wording at the end of the sentence after Requirement R2 concerning 60 months after the effective date of the standard. Including modifying the term “Responsible Entity”, Measure M2 would be as follows: “Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the [responsible entity] coordinated the Protection Systems for the Elements identified in Requirement R2[].”
Group
SPP Standards Review Group

Shannon V. Mickens
No
We ask the drafting team to conduct an analysis between FAC-001-1 and PRC-027-1 to ensure that there are no redundancy issues between the documentation. However, we still have concerns about the time commitment for documentation in reference to the internal coordination process and that it will not help improve reliability for the BES Elements. We agree with the concept contained in Requirement R1; however, we don't agree with scope of the internal coordination process for PRC-027-1.
We generally agree that Parts 1.1 through 1.5 of Requirement R1 includes the essential elements for the coordination process. However, we would ask the drafting team to provide more detailed information in the rationale box especially concerning the intent of Requirement R1.4 and R1.5. Some of our confusion was based around why was there a need for two procedures… along with proving compliance on the retrieval and coordination of the required data before implementation.
We would ask the drafting team to re-evaluate Measure M2 for we feel that the language should include coordination information prior to the 60 calendar month period as acceptable evidence.
Group
DTE Electric
Kathleen Black
No
If Documentation of Protection System Coordination is to be required, the specifics of the study should not be prescribed. Previous drafts did not dictate the specifics of a PSCS. However, Part 1.4 of R1 should remain to insure communication with other entities.
No
Each entity should be responsible for determining what makes up their coordination study/process.
This statement seems to already assume that a coordination process will be specified in the standard while Question 1 asks if one should be required.
No
If the intent of draft 5 was to change applicability from interconnecting elements to BES elements, shouldn't R2 be revised accordingly?
No Comments
None
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes
SMUD much prefers this process option to the previous options balloted. However, we continue to struggle with the idea that a standard is required to address intra-utility coordination. The greatest risk for a mis-coordination is at the seams between entities, not inside an entity.
Yes
SMUD agrees these steps form a coordination process. However, in smaller utilities, a rigid, formalized process is not required to ensure coordination and instead unnecessarily burdens the process with excessive compliance documentation. In contrast, large utilities require formalized processes and often have very specialized skill sets among their protection engineers and special facilities that require extra care. The SDT will need to develop a flexible process that applies to both.
We urge the SDT to develop flexibility into the process. SMUD currently uses the relay maintenance cycle to review settings. This makes our process time-based and in synch with the times found in PRC-005. We do this so that the relay tech makes only one trip to the relay. We are strongly opposed to any process that requires us to[[arbitrarily]] look for fault current changes and take actions out of cycle.

Yes
SMUD agrees with the three items listed, with the caveat that we feel coordination should be done only at the seams between entities and not internal to the entity.
No
The term “to demonstrate” in M2 leaves it too open at this point to know what depth of detail is needed. We are afraid we would need to show lots of coordination plots for every line, including the elements looking into the line and the elements the line looks out on. It seems to us this could balloon into a lot of paperwork. Perhaps an attestation by the engineer that the coordination was done per the process document would be sufficient?
We encourage the SDT to address functional obligations that would be managed by an internal group who would perform the actions in the requirement(s). This effectively eliminates the need for internal coordination and associate processes. As we have indicated in the previous responses we urge the SDT to allow an entity to coordinate relay settings, data and other associated equipment protection through an internal group.
Individual
Phil Hart
AECI
Yes
No
1. AECI believes the intended structure of this proposed standard is to require a process for all BES elements in a less burdensome R1, and require actual physical documentation in a more expanded, detailed R2. AECI agrees with this approach, however M1 currently does not reflect this approach. If the SDT intent of this standard is aligned with our interpretation, then the measure should not require actual documentation for the elements in R1, rather require only the procedure or process that is stated. Recommended language , [M1. Acceptable evidence includes, but is not limited to, electronic or physical dated records of the Responsible Entity’s process(es) to coordinate its Protection Systems, in accordance with Requirement R1 and its Parts.] 2. If the intent of R2 is to require documentation of coordination for a fewer, but more critical list of elements, then the cutoff levels for generation should reflect this. AECI would suggest the SDT move the 75 MVA cut-off to 1500 MVA to align with industry accepted definition of a generation level that is deemed critical to BES reliability. At the least, the 75 MVA cutoff should be increased to some point, if not 1500 MVA. 75 MVA units have very little to no impact on the BES, and including them in this documentation requirement would only reduce entity focus on those elements that are critical, such as IROL related elements, and 200 kV plus interconnections (which AECI agrees should be documented). 3. AECI believes that requirement 1.2 is too constrictive, and should allow entities other methods to ensure that protection system settings are accurate. One method of this (which AECI is in the process of developing) is using a standardized, reviewed, template for settings construction. Settings that fall out of this template would then be reviewed through some quality assurance program. The current 1.2 is very close to allowing this type of quality review, however please keep in mind this template approach when revising the standard as to not eliminate this option for quality assurance.
No
1. AECI would strongly suggest that for whatever triggers are developed, they be condition based and not time based. Developing time based triggers would lead to monotonous paperwork that would otherwise be unnecessary.
Yes
AECI believes 60 calendar months is a reasonable time for documentation of coordination. To clarify, would the SDT be able to state if there will be any cutoff for the age of documentation that will be acceptable (would coordination documentation from 10 or 20 years ago still be good?).
Individual
Nick Braden
Modesto Irrigation District

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: "To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection System components operate in the intended sequence during Faults." PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii). Draft 5 of PRC-027-1 modifies the applicability of the standard to include "Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements," whereas, prior drafts of the standard limited the applicability to "Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements." With this change to the applicability, the coordination of Protection Systems for all "internal" or "intra-entity" connections between BES Elements are addressed.

Completed Actions	Date
Standard Authorization Request (SAR) posted for comment	June 11 – July 10, 2007
SAR approved	August 13, 2007
Draft 1 of PRC-001-2 posted for comment	September 11 – October 26, 2009
Draft 1 of PRC-027-1 posted for formal comment with ballot	May 21 – July 5, 2012
Draft 2 of PRC-027-1 posted for formal comment with ballot	November 16 – December 17, 2012
Draft 3 of PRC-027-1 posted for formal comment with ballot	June 4 – July 3, 2013.
Draft 4 of PRC-027-1 posted for formal comment with ballot	November 4 – December 31, 2013
Draft 5 of PRC-027-1 posted for informal comment	October 1 – October 21, 2014

Draft 5 of PRC-027-1 posted for formal comment with ballot	April 1 – May 15, 2015

Anticipated Actions	Date
10-day final ballot	June, 2015
NERC Board (BOT) adoption	August, 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A

Protection System Issues Addressed by Other Projects:

Fault clearing is the only aspect of protection coordination addressed by Reliability Standard PRC-027-1. Other protection issues, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects:

- Underfrequency Load shedding programs are addressed in PRC-006-2.
- Undervoltage Load shedding programs are addressed in PRC-010-1.
- Generator performance during declined frequency and voltage excursions is addressed in PRC-024-1.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-1.
- Transmission relay loadability is addressed in PRC-023-3.
- Generator relay loadability is addressed in PRC-025-1.
- Protective relay response during stable power swings is addressed in PRC-026-1.
- Protection System Misoperations (including those caused by coordination issues) are addressed in PRC-004-3.

The SPCSDT contends that including aspects of protection coordination other than Fault coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Coordination of Protection System Performance During Faults**
2. **Number:** PRC-027-1
3. **Purpose:** To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Owner
     - **4.1.2.** Generator Owner
     - **4.1.3.** Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 below)
   - **4.2. Facilities:**

     Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements
5. **Effective Date:**
   See Implementation Plan for PRC-027-1, Project 2007-06 System Protection Coordination.

B. Requirements and Measures

Rationale for Requirement R1:

Coordinated Protection Systems enhance BES reliability by reducing the risk of power system instability or Cascading by isolating the faulted equipment in a timely manner – leaving the remainder of the System operational and capable of withstanding the next contingency. When Faults occur, properly coordinated protection systems minimize the number of power system Elements removed from service and protect power system equipment from damage. The stated purpose of this standard is: To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults. Requirement R1 captures this intent by mandating an entity establish a process that, when followed, will facilitate consistent results for developing settings for its BES Protection Systems. The drafting team contends the parts listed below are essential elements of the coordination process.

Part 1.1 Reviewing and updating the information required to coordinate Protection Systems maximizes the likelihood that the process of reviewing and developing settings is completed using accurate, up-to-date information. Examples of information that potentially need to be reviewed are: short-circuit databases, line and transformer impedances, station configurations, current and voltage transformer ratios, adjacent Protection System settings, and relay and control functional drawings.

Part 1.2 Reviewing the affected Protection System settings when System changes occur maintains coordination. Examples of System changes are: new or revised Protection System installations, changes to a transmission system Element that alters any sequence or mutual coupling impedance, changes to generator unit(s) that result in a change in impedance, or changes to the generator step-up transformer(s) that result in a change in impedance.

Part 1.3 Periodically reviewing Fault current values and/or existing entity-designated Protection System settings maximizes the likelihood that small incremental changes to the power system have not altered the coordination of the Protection Systems. Based on the Protection System design and/or susceptibility to changes in Fault current, applicable entities (Transmission Owners, Generator Owners, and Distribution Providers) will designate what Protection Systems must be included in the review(s) to ensure these Protection Systems continue to operate in the intended sequence during Faults. For example, a current differential scheme may not need to be included because changes in Fault current will not affect the coordination of this system. However, an instantaneous overcurrent element would need to be reviewed because changes in Fault current may cause this element to operate for Faults outside its zone of protection. Part 1.3 provides entities the flexibility to use a Fault current-based or a time-based methodology, or a combination of the two.

The Fault current-based option requires an entity to first establish a Fault current baseline for Protection Systems at the bus under study to be used as a control point for future Fault current studies. Fault current changes on the System are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. To minimize this risk, the drafting team chose a maximum Fault current deviation of 15 percent (as compared to the entity-established baseline) and a maximum time interval of six calendar years for the Fault current analysis to be performed. The drafting team contends these maximums provide an entity with latitude to choose a Fault current threshold and time interval that best matches its protection philosophy, Protection System maintenance schedule, or other business considerations. (See the Supplemental Materials section for more detailed discussion.)

As a second option, an entity may choose to establish a periodic review of its existing Protection System settings. The maximum time interval for the review is six calendar years. The drafting team assigned a six calendar year time interval because that corresponds to the maximum allowable maintenance period established for certain relays in PRC-005-2; consequently, this allows Protection System settings revisions to be included with associated maintenance.

As a third option, an entity may choose to apply a combination of the two review methodologies based on criteria such as voltage level or Protection System application.

Part 1.4 A quality review of the Protection System settings minimizes the introduction of human error into the development of Protection System settings and helps to ensure the settings produced meet the entity's design specifications for Protection System performance. Peer reviews, automated checking programs, and entity-developed review procedures, are all examples of quality reviews.

Part 1.5 The coordination of Protection Systems associated with BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) is critical to the reliability of the BES. Communications among these entities is essential so potential coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A method to review and update the information required to develop new or revised Protection System settings.

1.2. A review of Protection System settings affected by System changes.

1.3. A review of existing entity-designated[1] Protection System settings based on one of the following:

- **Periodic Fault current studies:** A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the bus under study, and evaluated in a time interval not to exceed six calendar years, or
- **Periodic review of Protection System settings:** A time interval, not to exceed six calendar years, or
- A combination of the above.

1.4. A quality review of the Protection System settings prior to implementation.

[1] Based on the Protection System design and/or susceptibility to changes in Fault current, applicable entities (Transmission Owners, Generator Owners, and Distribution Providers) will designate what Protection Systems must be included in the review(s) to ensure these Protection Systems continue to operate in the intended sequence during Faults.

1.5. For new or revised Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, (Transmission Owners, Generator Owners, and Distribution Providers), procedures to:

1.5.1. Communicate the proposed Protection System settings with the other functional entities.

1.5.2. Review proposed Protection System settings provided by other functional entities, and respond regarding the proposed settings. The response should identify any coordination issue(s) or affirm that no coordination issue(s) were identified.

1.5.3. Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation.

M1. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the responsible entity established a process to develop settings for its BES Protection Systems, in accordance with Requirement R1.

Rationale for Requirement R2:
Implementing the process established in Requirement R1 ensures a consistent approach to the development of Protection System settings such that BES Protection Systems operate in the intended sequence during Faults.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement the process established in accordance with Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the responsible entity implemented the process established in accordance with Requirement R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask

an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner and Distribution Provider that owns Protection Systems designed to detect Faults on BES Elements shall each keep data or evidence to show compliance with Requirements R1 and R2, and Measures M1 and M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include one Part.	The responsible entity established a process in accordance with Requirement R1, but failed to include two or more Parts. OR The responsible entity failed to establish a process in accordance with Requirement R1.
R2.	N/A	N/A	The responsible entity implemented the process established in accordance with Requirement R1, but failed to implement one Part.	The responsible entity implemented the process established in accordance with Requirement R1, but failed to implement two or more Parts. OR The responsible entity failed to implement the process established in accordance with Requirement R1.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee – Technical Reference Document "Power Plant and Transmission System Protection Coordination" (the most current version).

NERC System Protection and Control Task Force – Assessment of Standard PRC-001-0 – System Protection Coordination (December 7, 2006)

NERC System Protection and Control Task Force – The Complexity of Protecting Three-Terminal Transmission Lines (September 2006)

Implementation Plan **(DELETE GREEN TEXT PRIOR TO PUBLISHING) A link should be added to the implementation plan and other important documents associated with the standard once finalized.**

Version History

Version	Date	Action	Change Tracking
1	TBD	Adopted by NERC Board of Trustees	New

Purpose:

To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.

Coordinated Protection Systems enhance BES reliability by reducing the risk of power system instability or Cascading by isolating the faulted equipment in a timely manner – leaving the remainder of the System operational and capable of withstanding the next contingency. When Faults occur, properly coordinated protection systems minimize the number of power system Elements removed from service and protect power system equipment from damage. This standard requires that entities establish and implement a process to coordinate their BES Protection Systems to operate in the intended sequence during Faults.

Requirement R1:

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults.

This requirement directs the applicable entities to establish a process to develop settings for coordinating its BES Protection Systems such that they operate in the intended sequence during Faults. The drafting team contends the items included as elements of the process are key to ensuring the development of accurate settings, as well as providing internal and external checks to minimize the possibility of errors in the development of these settings.

In developing this Standard, the System Protection Coordination Standard Drafting Team (SPCSDT) referenced various publications that discuss protective relaying theory and application. The following description of "coordination of protection" is from the pending revision of IEEE C37.113, Guide for Protective Relay Applications to Transmission Lines:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

The drafting team acknowledges that entities may have differing technical criteria for the development of Protection System settings based on their own internal tolerances. These philosophies can vary based on system topology, protection technology utilized, as well as historical knowledge. As such, a single definition or criteria for 'Protection System coordination' is not practical.

The drafting team also recognizes that the coordination of some Protection Systems may seem unnecessary, such as for a line that is protected by dual current differential relays. Where backup Protection Systems are enabled to operate based on current level or apparent impedance with some definite or inverse time delay, it is important to ensure those Protection Systems coordinate with other Elements' Protection Systems such that tripping does not unnecessarily occur for Faults outside of the differential zone.

Part 1.1 A method to review and update the information required to develop new or revised Protection System settings.

Two important studies used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers are the short circuit and protective device coordination studies. Having a method of reviewing and updating information to make sure it is correct in short circuit studies and protective device coordination studies is necessary to guarantee that these two studies accurately reflect the physical power system being considered in the development of Protection System relay settings. The results of the studies are only as accurate as the information that their calculations are based on.

A short circuit study is an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical Fault. The results of a short circuit study are used as the basis for protective device coordination studies. Because a short circuit study should, as accurately as possible, model the actual network it is representing in order to calculate true Fault currents, the method of the review and update of information for the short circuit study might include the following:

1. A review of applicable BES line, transformer, and generator impedances to verify they are correct.
2. A review of the network model to confirm the network in the study accurately reflects the configuration of the actual system, or how the system will be configured when the proposed relay settings are installed.
3. A review of interconnected Transmission Owner, Generator Owner, or Distribution Provider's information to determine whether their Systems are correctly modeled in the short circuit study.

A protective device coordination study is performed to determine the settings for protective relays to operate in the intended sequence during Faults. Protective device coordination studies are used to evaluate the application of protective devices, identify problem areas in the network, and determine solutions for existing or future device coordination.

A protective device coordination study should, as accurately as possible, represent the actual or proposed protective relaying in the network. The method for reviewing and updating information for the protective device coordination study might include the following:

1. A review of current and voltage transformer ratios, Protection System settings and the relay manufacture's curve characteristics to ensure the information in the protective device coordination study is correct.
2. A review of the adjacent relay settings to ensure those settings coordinate with the relay settings under study.
3. A review of interconnected Transmission Owner, Generator Owner, or Distribution Provider's actual and proposed relay setting changes to determine whether they are accurately represented in the protective device coordination study.

Other information that may be of value includes engineering drawings such as single-line diagrams, three-line diagrams, and relay and control functional drawings.

Part 1.2 A review of Protection System settings affected by System changes.

Reviewing the affected Protection System settings when System changes occur maintains coordination. Examples of System changes are: new or revised Protection System installations, changes to a transmission system Element that alter any sequence or mutual coupling impedance, changes to generator unit(s) that result in a change in impedance, or changes to the generator step-up transformer(s) that result in a change in impedance.

Part 1.3 A review of existing entity-designated Protection System settings based on one of the following:

Periodically reviewing Fault current values and/or existing entity-designated Protection System settings maximizes the likelihood that small incremental changes to the power system have not altered the coordination of the Protection Systems. Based on the Protection System design and/or susceptibility to changes in Fault current, an entity will designate what Protection Systems must be included in the review to ensure these Protection Systems continue to operate in the intended sequence during Faults. For example, a current differential scheme may not need to be included because changes in Fault current will not affect the coordination of this system. However, settings for an instantaneous overcurrent element would need to be reviewed because changes in Fault current may cause this element to operate for Faults outside its zone of protection. Based on stakeholder comments and industry knowledge, the drafting team chose two 'triggers' for initiating a review of existing Protection System settings. Entities have the flexibility to use a Fault current-based or a time-based methodology, or a combination of the two.

- (Option 1) A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the busunder study, and evaluated in a time interval not to exceed six calendar years, or Fault current changes on the System are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. To minimize this risk, the drafting team chose a maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) and a maximum time interval of six calendar years for the Fault current analysis to be performed. The drafting team contends these maximums provide an entity with latitude to choose a Fault current threshold and time interval that best matches its protection philosophy, Protection System maintenance schedule, or other business considerations. The Fault current-based option requires an entity to first establish a Fault current baseline to be used as a control point for future Fault current studies. The Fault current values used in the percent change calculation, whether three-phase or phase-to-ground Fault currents, are typically determined with maximum generation and all Facilities assumed to be in service.

  The baseline can be the Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect. These baseline Fault current values can be at the bus level or at the individual Element level. When performing the periodic Fault current comparison, the entity would continue to compare actual Fault current values gathered during the review against the originally established baseline values until a condition occurs that necessitates the establishment of a new baseline.

Example: Baseline is established at 10,000 amps. During the first short-circuit review, it is discovered that Fault current has increased to 11,250 amps (12.5 % change); consequently, no Protection System settings review is required since the increase is below 15% and the baseline value for next review remains at 10,000 amps. However, during the next short-circuit review, the Fault current has increased to 11,500 (15% change); therefore, a review of the Protection System settings is required, and a new baseline of 11,500 amps would be established.

- (Option 2) A time interval, not to exceed six calendar years, or

  As a second option, an entity may choose a time-based methodology to review Protection System settings eliminating the necessity of establishing a Fault current baseline and periodically performing short-circuit studies. This option provides the entity the flexibility to choose an interval of up to six calendar years for performing the Protection System settings review.

- (Option 3) A combination of the above.

  As a third option, an entity has the flexibilityto apply a combination of the two methodologies based on criteria such as voltage level or Protection System applications. For example, an entity may choose the periodic Protection System review (option 2) and review its Facilities operated above 300 kV on a six year interval, while choosing to use the Fault current review (option 1) for its Facilities operated below 300 kV and periodically compare available Fault currents against the Fault current baseline.

Part 1.4 A quality review of the Protection System settings prior to implementation.

A quality review of the Protection System settings prior to implementation reduces the possibility of human error being introduced into the development of the Protection System settings. A quality review is any systematic process of verifying that the developed settings meet the entity's specific requirements for Protection System performance. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of quality reviews.

Part 1.5 For new or revised Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, (Transmission Owners, Generator Owners, and Distribution Providers), procedures to:

Part 1.5 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities. Communications among these entities is essential so potential coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

> **1.5.1** Communicate the proposed Protection System settings with the other functional entities.

Part 1.5.1 mandates entities have a procedure to communicate proposed Protection System settings with other entities. These communications ensure that the other entities have the necessary information to review the settings and determine if there are any coordination issues.

> **1.5.2** Review proposed Protection System settings provided by other functional entities, and respond regarding the proposed settings. The response should identify any coordination issue(s) or affirm that no coordination issue(s) were identified.

Part 1.5.2 mandates the entity receiving proposed Protection System settings have a procedure to review the settings and respond to the entity that initiated the proposed changes. This ensures that the proposed settings are reviewed and the initiating entity receives a response. The response must include any identified coordination issues, or affirm that no issues were identified.

> **1.5.3** Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation.

Part 1.5.3 mandates the entity have a procedure to verify that any identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation. This ensures any potential impact to BES reliability are minimized.

The drafting team recognizes there could be instances where coordination issues are identified that pose minimum risk to the reliability of the BES, and the entities, therefore, agree to allow the unmitigated issue to remain. It is also recognized that coordination issues identified during a project may not be immediately resolved if the resolution involves additional system modifications not identified in the initial project scope. The drafting team also recognizes there are situations where entities' protection philosophies differ but they can agree that there were no identified coordination issues.

Requirement R2:

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall implement the process established in accordance with Requirement R1.

This requirement directs the applicable entities to implement the process established in Requirement R1. Implementing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, minimizes the possibility of introducing errors, and maximizes the likelihood of maintaining a coordinated Protection System.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2007-06 System Protection Coordination

Approvals Requested

- PRC-027-1 – Coordination of Protection System Performance During Faults
- PRC-001-3 – System Protection Coordination

Retirements Requested

- PRC-001-1.1(ii) – System Protection Coordination

Prerequisite Approvals

- N/A

Applicable Entities

Standard	Applicable Entities					
	TO	GO	DP	TOP	GOP	BA
PRC-027-1: Coordination of Protection System Performance During Faults	X	X	X			
PRC-001-3: System Protection Coordination				X	X	X

New or Modified Term(s) Used in NERC Reliability Standards

- None

Effective Date of New or Revised Standards

PRC-027-1 – Coordination of Protection System Performance During Faults

PRC-027-1 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

PRC-001-3 – System Protection Coordination
PRC-001-3 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement

PRC-001-1.1(ii) – System Protection Coordination

PRC-001-1.1(ii) – System Protection Coordination shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter that is twelve (12) months after the date that the PRC-001-3 is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, PRC-001-1.1(ii) shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter that is twelve (12) months after the date that the PRC-001-3 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Unofficial Comment Form

Project 2007-06 System Protection Coordination PRC-027-1 (Draft 5)

DO NOT use this form for submitting comments. Use the electronic form to submit comments on draft 5 of **PRC-027-1 – Coordination of Protection System Performance During Faults**. The form must be completed and submitted by **8 p.m. Eastern, Friday, May 15, 2015.**

If you have questions, contact Standards Developer, Al McMeekin, (via email) or at (404) 446-9675.

The project page may be accessed by clicking here.

Background Information

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: "*To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.*" Draft 4 of PRC-027-1 was posted for comment and ballot from 11/4/13 - 12/31/13. Following the posting, FERC staff from the Office of Electric Reliability raised concerns regarding the posted draft. The primary concern was that the proposed standard did not address the coordination of Protection Systems within a Transmission Owner's footprint, referred to as "internal" or "intra-entity" Protection Systems. Following discussions with NERC and FERC staff, the SPCSDT prepared a preliminary draft 5 of PRC-027-1 and sought stakeholder input on the conceptual standard during a 21-day informal comment period. Based on stakeholder comments received during the informal comment period, the drafting team modified the proposed standard.

Draft 5 of PRC-027-1 modifies the applicability of the standard to include "*Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements*," whereas, prior drafts of the standard limited the applicability to "*Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements.*" With this change to the applicability, the coordination of Protection Systems for all "internal" or "intra-entity" connections between BES Elements are addressed. PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii); therefore, the SPCSDT is proposing the retirement of those Requirements from PRC-001-1.1(ii). The SPCSDT has included a redlined version of PRC-001-1.1(ii) and a clean PRC-001-3. PRC-001-3 contains the remaining Requirements R1, R2, R5, and R6 as well as updated pro forma language for the "Effective Date" and "Compliance" sections of the standard.

Draft 5 of PRC-027-1 consists of two proposed requirements.

Requirement R1 mandates that entities establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults; and stipulates certain attributes that must be included in the process. Because entities' Protection System designs and philosophies vary greatly, the drafting team has included flexibility in developing the coordination processes.

Requirement R2 mandates that entities implement the process established in accordance with Requirement R1. The drafting team asserts that implementing each of the elements of the process will facilitate a consistent approach in the development of accurate Protection System settings, minimize the possibility of introducing errors, and maximize the likelihood of maintaining a coordinated Protection System.

The Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) is posting draft 5 of Reliability Standard PRC-027-1 "Protection System Coordination for Performance During Faults" for comment from April 1, 2015 to May 15, 2015.

Questions:

1. Do you agree that Parts 1.1 through 1.5 of Requirement R1 are the essential elements of a successful coordination process? Are there others that should be included? If not, please provide the basis for your disagreement and any proposed revisions or additions.

   ☐ Yes
   ☐ No
   Comments:

2. Do you agree with the proposed Measures? If not, please provide the basis for your disagreement and your proposed revisions.

   ☐ Yes
   ☐ No
   Comments:

3. Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.

   ☐ Yes
   ☐ No
   Comments:

4. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

   Comments:

Mapping of Requirements from PRC-001-1.1(ii) to PRC-027-1

Project 2007-06 System Protection Coordination

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.	Being addressed by Project 2007-06.2 Phase 2: System Protection Coordination	N/A
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	Being addressed by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. • Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition. R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	PRC-027-1: R1 and R2 Note: Applicability changed to GO, TO and DP	R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults. The process shall include: 1.1. A method to review and update the information required to develop new or revised Protection System settings. 1.2. A review of Protection System settings affected by System changes. 1.3. A review of existing entity-designated Protection System settings based on one of the following: • **Periodic Fault current studies:** A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the bus under study, and evaluated in a time interval not to exceed six calendar years, or • **Periodic review of Protection System settings:** A time interval, not to exceed six calendar years, or • A combination of the above. 1.4. A quality review of the Protection System settings prior to implementation.

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		1.5. For new or revised Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, (Transmission Owners, Generator Owners, and Distribution Providers), procedures to: 1.5.1. Communicate the proposed Protection System settings with the other functional entities. 1.5.2. Review proposed Protection System settings provided by other functional entities, and respond regarding the proposed settings. The response should identify any coordination issue(s) or affirm that no coordination issue(s) were identified. 1.5.3. Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation. R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement the process established in accordance with Requirement R1.
R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator	PRC-027-1: R1 and R2	R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process to develop settings for its BES Protection Systems to

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
Operators, Transmission Operators, and Balancing Authorities.	Note: Applicability changed to GO, TO and DP	operate in the intended sequence during Faults. The process shall include: 1.1. A method to review and update the information required to develop new or revised Protection System settings. 1.2. A review of Protection System settings affected by System changes. 1.3. A review of existing entity-designated Protection System settings based on one of the following: • **Periodic Fault current studies:** A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the bus under study, and evaluated in a time interval not to exceed six calendar years, or • **Periodic review of Protection System settings:** A time interval, not to exceed six calendar years, or • A combination of the above. 1.4. A quality review of the Protection System settings prior to implementation. 1.5. For new or revised Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		entities (Transmission Owners, Generator Owners, and Distribution Providers), procedures to: 1.5.1. Communicate the proposed Protection System settings with the other functional entities. 1.5.2. Review proposed Protection System settings provided by other functional entities, and respond regarding the proposed settings. The response should identify any coordination issue(s) or affirm that no coordination issue(s) were identified. 1.5.3. Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation. R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement the process established in accordance with Requirement R1.
R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:	Being addressed by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems. R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.		
R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Being addressed by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Violation Risk Factor and Violation Severity Level Justification Document

Project 2007-06 System Protection Coordination

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange

- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because an entity's failure to establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could directly affect the electrical state or the capability of the Bulk-Power System. However, a violation of this requirement is unlikely to lead to Bulk-Power System instability, separation, or cascading failures. A medium VRF assignment is appropriate given the level of risk to System performance resulting from the lack of coordinated Protection Systems. For these reasons, the requirement meets the NERC criteria for a Medium VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) system modeling and data exchange. Requirement R1 mandates that entities establish a process to address all aspects of BES Protection System coordination, including the updating of modeling information and the exchange of Protection System data with other owners when applicable (see, Requirement R1, Parts 1.1 and 1.5).

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	Because Parts (previously called sub-Requirements) are no longer assigned individual VRFs, this Guideline is no longer applicable.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-2, Requirements R1 and R2 which are related to developing and documenting a Protection System Maintenance Program and have VRFs of Medium.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because an entity's failure to establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could directly affect the electrical state or the capability of the Bulk-Power System. However, a violation of this requirement is unlikely to lead to Bulk-Power System instability, separation, or cascading failures. A medium VRF assignment is appropriate given the level of risk to System performance resulting from the lack of coordinated Protection Systems. For these reasons, the requirement meets the NERC criteria for a Medium VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include one Part.	The responsible entity established a process in accordance with Requirement R1, but failed to include two or more Parts. OR The responsible entity failed to establish a process in accordance with Requirement R1.

VSL Justifications for PRC-027-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no "consequence of lowering the current level of compliance."
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Severe and High VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-027-1, Requirement R2	
VRF for Requirement R2 is High	
NERC VRF Discussion	A high VRF is appropriate for Requirement R2 because failure to implement the process established in Requirement R1 could, "under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition." This requirement meets the NERC criteria for a High VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS. Requirement R2 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) system modeling and data exchange. Requirement R2 mandates that entities implement the process established in Requirement R1 that incorporates all actions necessary to achieve coordination of Protection Systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	Because Parts (previously called sub-Requirements) are no longer assigned individual VRFs, this Guideline is no longer applicable.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-2, Requirements R3 and R4 which are related to implementing time-based and performance-based maintenance program(s) respectively for Protection Systems.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A high VRF is appropriate for Requirement R2 because failure to implement the process established in Requirement R1 could, "under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition." This requirement meets the NERC criteria for a High VRF.

VRF Justifications for PRC-027-1, Requirement R2	
VRF for Requirement R2 is High	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity implemented the process established in accordance with Requirement R1, but failed to implement one Part.	The responsible entity implemented the process established in accordance with Requirement R1, but failed to implement two or more Parts. OR The responsible entity failed to implement the process established in accordance with Requirement R1.

VSL Justifications for PRC-027-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no “consequence of lowering the current level of compliance.”
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Severe and High VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

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Standards Announcement

Reminder

Project 2007-06 System Protection Coordination
PRC-027-1

Additional Ballot and Non-binding Poll Open through May 15, 2015

Now Available

An additional ballot for draft 5 of **PRC-027-1 – Coordination of Protection System Performance During Faults** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Friday, May 15, 2015**.

PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii); therefore, the System Protection Coordination standard drafting team (SPCSDT) is proposing the retirement of those Requirements from PRC-001-1.1(ii). The SPCSDT has included a redlined version of PRC-001-1.1(ii) and a clean PRC-001-3. PRC-001-3 contains the remaining Requirements R1, R2, R5, and R6 as well as updated pro forma language for the "Effective Date" and "Compliance" sections of the standard.

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of PRC-027-1.

Balloting

Members of the ballot pool associated with this project may log in and submit their vote for the standard and non-binding poll by clicking here. If you experience any difficulties in using the electronic form, contact Arielle Cunningham.

Note: If a member cast a vote in the previous ballot, that vote will not carry over to this additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in this ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

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Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Formal Comment Period Open through May 15, 2015
Ballot Pools Forming through April 30, 2015

Balloting and commenting for this project are in the Standards Balloting & Commenting System (SBS)

Now Available

A 45-day formal comment period for draft 5 of **PRC-027-1 – Coordination of Protection System Performance During Faults** is open through **8 p.m. Eastern on Friday, May 15, 2015.**

PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii); therefore, the System Protection Coordination standard drafting team (SPCSDT) is proposing the retirement of those Requirements from PRC-001-1.1(ii). The SPCSDT has included a redlined version of PRC-001-1.1(ii) and a clean version of PRC-001-3. PRC-001-3 contains the remaining Requirements R1, R2, R5, and R6 as well as updated pro forma language for the "Effective Date" and "Compliance" sections of the standard.

SBS Login, Registration, Validation and Permissions

To **comment** in the SBS, you must have a contributor, voter, or proxy role.
To **join a ballot pool and vote** in the SBS, you must have a voter role.
To be a **proxy** and vote in the SBS, you must have a proxy role.

To register to become a proxy or voter in the SBS:

- Go to 'My User Profile'
- Select 'Click Here' to request additional permissions
- Select 'Voter' or 'Proxy Voter'

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Thursday, April 30, 2015**.

Registered Ballot Body members may join the ballot pools here.

If you had previously joined the ballot pools for PRC-027-1, you **must** join these ballot pools to cast a vote. Previous PRC-027-1 ballot pool members **will not** be carried over to these ballot pools.

The ballot and non-binding poll for this posting are **additional**. Since the ballot pools for this project are outdated, new ballot pools are being formed in the SBS.

Next Steps

An **additional** ballot for the standard and ~~a~~ non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **May 6-15, 2015.**

Standards Development Process

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

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Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Formal Comment Period Open through May 15, 2015
Ballot Pools Forming through April 30, 2015

Balloting and commenting for this project are in the Standards Balloting & Commenting System (SBS)

Now Available

A 45-day formal comment period for draft 5 of **PRC-027-1 – Coordination of Protection System Performance During Faults** is open through **8 p.m. Eastern on Friday, May 15, 2015.**

PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii); therefore, the System Protection Coordination standard drafting team (SPCSDT) is proposing the retirement of those Requirements from PRC-001-1.1(ii). The SPCSDT has included a redlined version of PRC-001-1.1(ii) and a clean version of PRC-001-3. PRC-001-3 contains the remaining Requirements R1, R2, R5, and R6 as well as updated pro forma language for the "Effective Date" and "Compliance" sections of the standard.

SBS Login, Registration, Validation and Permissions

To **comment** in the SBS, you must have a contributor, voter, or proxy role.
To **join a ballot pool and vote** in the SBS, you must have a voter role.
To be a **proxy** and vote in the SBS, you must have a proxy role.

To register to become a proxy or voter in the SBS:

- Go to 'My User Profile'
- Select 'Click Here' to request additional permissions
- Select 'Voter' or 'Proxy Voter'

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Thursday, April 30, 2015**.

Registered Ballot Body members may join the ballot pools here.

If you had previously joined the ballot pools for PRC-027-1, you **must** join these ballot pools to cast a vote. Previous PRC-027-1 ballot pool members **will not** be carried over to these ballot pools.

The ballot and non-binding poll for this posting are **additional**. Since the ballot pools for this project are outdated, new ballot pools are being formed in the SBS.

Next Steps

An **additional** ballot for the standard and ~~a~~ non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **May 6-15, 2015.**

Standards Development Process

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

North American Electric Reliability Corporation
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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2007-06 System Protection Coordination

Additional Ballot and Non-binding Poll Results

Now Available

A formal comment period and additional ballot for **Project 2007-06 System Protection Coordination** as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern, Friday, May 15, 2015.**

The project involves two standards: **PRC-027-1 – Coordination of Protection System Performance During Faults and PRC-001-3 – System Protection Coordination.** PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii); therefore, the System Protection Coordination standard drafting team (SPCSDT) is proposing the retirement of those Requirements from PRC-001-1.1(ii). The SPCSDT included a redlined version of PRC-001-1.1(ii) and a clean version of PRC-001-3 which contains the remaining Requirements R1, R2, R5, and R6 as well as updated pro forma language for the "Effective Date" and "Compliance" sections of the standard.

The additional ballot for **PRC-027-1 and PRC-001-3** achieved a quorum, but did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides detailed results for the ballot and non-binding poll.

Ballot	Non-binding Poll
Quorum /Approval	Quorum/Supportive Opinions
81.79% / 39.63%	81.13% / 39.25%

Next Steps

The SPCSDT will consider all comments received during the formal comment period, make revisions to the standard(s), and post for an additional ballot.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

North American Electric Reliability Corporation
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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/12)
Ballot Name: 2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) IN 1 ST
Voting Start Date: 5/6/2015 12:01:00 AM
Voting End Date: 5/15/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 274
Total Ballot Pool: 332
Quorum: 82.53
Weighted Segment Value: 39.65

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	82	1	26	0.4	39	0.6	0	3	14
Segment: 2	7	0.4	1	0.1	3	0.3	0	0	3
Segment: 3	80	1	26	0.4	39	0.6	0	3	12
Segment: 4	30	1	5	0.208	19	0.792	0	2	4
Segment: 5	74	1	18	0.321	38	0.679	0	3	15
Segment: 6	47	1	14	0.368	24	0.632	0	2	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	2	0.1	0	0	1	0.1	0	0	1

Segment: 10	8	0.6	5	0.5	1	0.1	0	0	2
Totals:	332	6.3	97	2.498	164	3.802	0	13	58

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	American Transmission Company, LLC	Andrew Pusztai		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	BC Hydro and Power Authority	Patricia Robertson		Negative	Comments Submitted
1	Beaches Energy Services	Don Cuevas		Negative	Third-Party Comments
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

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1	Black Hills Corporation	Wes Wingen		Abstain	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Third-Party Comments
1	Colorado Springs Utilities	Shawna Speer		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Negative	Comments Submitted
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Larry Nash		None	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis	marcus lotto	None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
1	Exelon	Chris Scanlon		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	William Smith		Negative	Comments Submitted

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1	Georgia Transmission Corporation	Jason Snodgrass	Greg Davis	Negative	Third-Party Comments
1	Great Plains Energy - Kansas City Power and Light Co.	Daniel Gibson		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Negative	Third-Party Comments
1	Iberdrola - Central Maine Power Company	Joe Turano		Negative	Third-Party Comments
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Affirmative	N/A
1	JEA	Ted Hobson	Thomas McElhinney	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Doug Bantam		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A

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1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard		Negative	Third-Party Comments
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Alan MacNaughton		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Affirmative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Negative	Third-Party Comments
1	PNM Resources - Public Service	Laurie Williams		Negative	Comments Submitted

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	Company of New Mexico				
1	Portland General Electric Co.	John Walker		Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Denise Lietz		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Negative	Comments Submitted
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		Negative	Third-Party Comments
1	SaskPower	Wayne Guttormson		None	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
1	Southern Illinois Power Cooperative	William Hutchison		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A

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1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Negative	Third-Party Comments
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Negative	Comments Submitted
2	California ISO	Richard Vine		None	N/A
2	Electric Reliability Council of Texas, Inc.	christina bigelow		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula	Mark Wilson	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Sarah Kist		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Basin Electric Power	Jeremy Voll		Negative	Third-Party

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	Cooperative				Comments
3	BC Hydro and Power Authority	Pat Harrington		Negative	Comments Submitted
3	Beaches Energy Services	Steven Lancaster		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Bartow, Florida	Matt Culverhouse		None	N/A
3	City of Garland	Ronnie Hoeinghaus		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Negative	Third-Party Comments
3	City of Leesburg	Chris Adkins		Negative	Third-Party Comments
3	City of Redding	Bill Hughes	Mary Downey	Negative	Third-Party Comments
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Charles Morgan		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	CPS Energy	Brian Bartos		Affirmative	N/A

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3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Cindy Stewart	Richard Hoag	Negative	Comments Submitted
3	Florida Municipal Power Agency	Joe McKinney		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Great Plains Energy - Kansas City Power and Light Co.	Joshua Bach		Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski		Negative	Comments Submitted
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi	Stephen Sines	Negative	Comments Submitted

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3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Modesto Irrigation District	Jack Savage	Nick Braden	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		None	N/A
3	PNM Resources	Michael Mertz		None	N/A

3	Portland General Electric Co.	Thomas Ward		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	Comments Submitted
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Negative	Comments Submitted
3	Santee Cooper	James Poston		Negative	Third-Party Comments
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Negative	Third-Party Comments
3	Seattle City Light	Dana Wheelock		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Negative	Comments Submitted
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A

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3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-County Electric Cooperative, Inc.	Chris Giles		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
3	We Energies - Wisconsin Electric Power Marketing	Jim Keller		Negative	Comments Submitted
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Negative	Third-Party Comments
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Negative	Third-Party Comments
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Negative	Third-Party Comments
4	City of Redding	Nick Zettel	Mary Downey	Negative	Third-Party Comments
4	City of Winter Park	Mark Brown		Negative	Third-Party Comments
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Negative	Comments Submitted
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	Comments Submitted
4	Flathead Electric Cooperative	Russ Schneider		Negative	Comments Submitted
4	Florida Municipal	Carol Chinn		Negative	Comments

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	Power Agency				Submitted
4	Fort Pierce Utilities Authority	Thomas Parker		Negative	Third-Party Comments
4	Georgia System Operations Corporation	Guy Andrews		Negative	Third-Party Comments
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	None	N/A
4	Keys Energy Services	Stanley Rzad		Negative	Third-Party Comments
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Negative	Third-Party Comments
4	Oklahoma Municipal Power Authority	Ashley Stringer		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Negative	Comments Submitted
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	Comments Submitted
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative	Comments Submitted

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4	Utility Services, Inc.	Brian Evans-Mongeon	brian robinson	None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski	Matthew Beilfuss	Negative	Comments Submitted
4	Z_NA	Christopher Plante		Abstain	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Scott Takinen		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		None	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Third-Party Comments
5	BC Hydro and Power Authority	Clement Ma		Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Third-Party Comments
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City and County of San Francisco	Daniel Mason		None	N/A
5	City of Garland	Minh Ngo		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted

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5	City of Redding	Paul Cummings	Mary Downey	Negative	Third-Party Comments
5	City Water, Light and Power of Springfield, IL	Steve Rose		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Colorado Springs Utilities	Kaleb Brimhall		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Essential Power, LLC	Gerry Adamski		Negative	Comments Submitted
5	Exelon	Vince Catania		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	David Schumann		Negative	Comments Submitted
5	Golden Spread	Chip Koloini	Sara Bednar	None	N/A

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	Electric Cooperative, Inc.				
5	Great Plains Energy - Kansas City Power and Light Co.	Brett Holland		Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Hydro-Qu?bec Production	Roger Dufresne	manon paquet	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Negative	Third-Party Comments
5	Muscatine Power and Water	Mike Avesing		Negative	Third-Party Comments
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
5	New York Power Authority	Wayne Sipperly		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Affirmative	N/A

5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Oxy - Ingleside Cogeneration LP	Michelle D'Antuono		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Negative	Third-Party Comments
5	Portland General Electric Co.	Barbara Croas		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		None	N/A
5	Santee Cooper	Lewis Pierce		Negative	Third-Party Comments
5	Seattle City Light	Mike Haynes		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public	Chris Mattson		Negative	Comments

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	Utilities (Tacoma, WA)				Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Erika Doot		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Linda Horn		Negative	Comments Submitted
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Negative	Comments Submitted
5	Z_NA	Donald Lock		Negative	Third-Party Comments
6	ACES Power Marketing	Ben Engelby		Abstain	N/A
6	AEP - AEP Marketing	Edward P Cox		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Randy Young		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Brenda Anderson		Affirmative	N/A
6	City of Redding	Marvin Briggs	Mary Downey	Negative	Third-Party Comments
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party

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					Comments
6	Colorado Springs Utilities	Shannon Fair		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Louis Slade		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker		Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik	Simon Tanapat	Negative	Comments Submitted
6	Modesto Irrigation District	James McFall	Nick Braden	Negative	Third-Party Comments
6	New York Power Authority	Shivaz Chopra		Negative	Third-Party Comments
6	NextEra Energy -	Silvia Mitchell		Negative	Third-Party

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	Florida Power and Light Co.				Comments
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		None	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
6	Omaha Public Power District	Mark Trumble		None	N/A
6	Platte River Power Authority	Carol Ballantine		Negative	Third-Party Comments
6	Portland General Electric Co.	Shawn Davis		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Stephen York		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Negative	Comments Submitted
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Negative	Third-Party Comments
6	Seattle City Light	Dennis Sismaet		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Negative	Comments Submitted

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6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Tiffany Lake		Affirmative	N/A
6	Z_NA	Elizabeth Davis		Negative	Third-Party Comments
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Negative	Third-Party Comments
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		None	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Negative	Third-Party Comments
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Joe Spencer		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 332 of 332 entries

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BALLOT RESULTS

Ballot Name: 2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) Non-Binding Poll IN 1 NB
Voting Start Date: 5/6/2015 12:01:00 AM
Voting End Date: 5/15/2015 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 258
Total Ballot Pool: 316
Quorum: 81.65
Weighted Segment Value: 38.65

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	77	1	22	0.44	28	0.56	0	13	14
Segment: 2	7	0.2	0	0	2	0.2	0	2	3
Segment: 3	76	1	22	0.431	29	0.569	0	12	13
Segment: 4	28	1	5	0.238	16	0.762	0	3	4
Segment: 5	71	1	14	0.318	30	0.682	0	12	15
Segment: 6	45	1	11	0.367	19	0.633	0	8	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	2	0.1	0	0	1	0.1	0	0	1
Segment:	8	0.6	4	0.4	2	0.2	0	1	1

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10									
Totals:	316	6.1	80	2.394	127	3.706	0	51	58

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		None	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		Negative	Comments Submitted
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric	Tony Kroskey		None	N/A

	Power Cooperative, Inc.				
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	Colorado Springs Utilities	Shawna Speer		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Negative	Comments Submitted
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		None	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis	marcus lotto	None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Negative	Comments Submitted
1	Georgia Transmission Corporation	Jason Snodgrass	Greg Davis	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	Daniel Gibson		Affirmative	N/A

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1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	JEA	Ted Hobson	Thomas McElhinney	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Doug Bantam		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard		Negative	Comments Submitted
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments

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					Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Affirmative	N/A
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
1	Portland General Electric Co.	John Walker		Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Denise Lietz		Affirmative	N/A

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1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Negative	Comments Submitted
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		None	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
1	Southern Illinois Power Cooperative	William Hutchison		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		None	N/A

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2	Electric Reliability Council of Texas, Inc.	christina bigelow		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula	Mark Wilson	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Sarah Kist		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
3	BC Hydro and Power Authority	Pat Harrington		Abstain	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

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3	City of Bartow, Florida	Matt Culverhouse		None	N/A
3	City of Green Cove Springs	Mark Schultz		Negative	Comments Submitted
3	City of Leesburg	Chris Adkins		Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Charles Morgan		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	CPS Energy	Brian Bartos		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Cindy Stewart	Richard Hoag	Negative	Comments Submitted
3	Florida Municipal Power Agency	Joe McKinney		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted

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3	Great Plains Energy - Kansas City Power and Light Co.	Joshua Bach		Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski		Negative	Comments Submitted
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi	Stephen Sines	Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Modesto Irrigation District	Jack Savage	Nick Braden	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Negative	Comments Submitted

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3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Abstain	N/A
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		None	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	Portland General Electric Co.	Thomas Ward		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Negative	Comments Submitted
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Negative	Comments Submitted

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3	Seattle City Light	Dana Wheelock		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Negative	Comments Submitted
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-County Electric Cooperative, Inc.	Chris Giles		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Negative	Comments Submitted
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Negative	Comments Submitted
4	City of Winter Park	Mark Brown		Negative	Comments

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					Submitted
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Negative	Comments Submitted
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	Comments Submitted
4	Flathead Electric Cooperative	Russ Schneider		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted
4	Fort Pierce Utilities Authority	Thomas Parker		Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	None	N/A
4	Keys Energy Services	Stanley Rzad		Negative	Comments Submitted
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility	Michael Ramirez	Joe Tarantino	Negative	Comments Submitted

	District				
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	Comments Submitted
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative	Comments Submitted
4	Utility Services, Inc.	Brian Evans-Mongeon	brian robinson	None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski	Matthew Beilfuss	Negative	Comments Submitted
4	Z_NA	Christopher Plante		Abstain	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Scott Takinen		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		None	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
5	BC Hydro and Power Authority	Clement Ma		Abstain	N/A
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Comments Submitted
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative,	Shari Heino		Negative	Comments Submitted

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	Inc.				
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Garland	Minh Ngo		Abstain	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
5	City Water, Light and Power of Springfield, IL	Steve Rose		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Colorado Springs Utilities	Kaleb Brimhall		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Essential Power, LLC	Gerry Adamski		Negative	Comments Submitted

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5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	David Schumann		Negative	Comments Submitted
5	Golden Spread Electric Cooperative, Inc.	Chip Koloini	Sara Bednar	None	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Brett Holland		Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Hydro-Qu?bec Production	Roger Dufresne	manon paquet	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Negative	Comments Submitted
5	Muscatine Power and Water	Mike Avesing		Negative	Comments Submitted

5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
5	Oxy - Ingleside Cogeneration LP	Michelle D'Antuono		None	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		None	N/A
5	Portland General Electric Co.	Barbara Croas		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		None	N/A
5	Santee Cooper	Lewis Pierce		Negative	Comments Submitted

5	Seattle City Light	Mike Haynes		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
5	Tennessee Valley Authority	Brandy Spraker		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Erika Doot		Negative	Comments Submitted
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Negative	Comments Submitted
5	Z_NA	Donald Lock		Negative	Comments Submitted
6	ACES Power Marketing	Ben Engelby		Negative	Comments Submitted
6	AEP - AEP Marketing	Edward P Cox		Abstain	N/A
6	APS - Arizona Public Service Co.	Randy Young		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Brenda Anderson		Affirmative	N/A

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6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker		Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik	Simon Tanapat	Negative	Comments Submitted
6	Modesto Irrigation District	James McFall	Nick Braden	Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern	Joe O'Brien		Affirmative	N/A

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	Indiana Public Service Co.				
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		None	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
6	Omaha Public Power District	Mark Trumble		None	N/A
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Shawn Davis		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Stephen York		Abstain	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Negative	Comments Submitted
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	Seattle City Light	Dennis Sismaet		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Negative	Comments Submitted

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6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Tiffany Lake		Affirmative	N/A
6	Z_NA	Elizabeth Davis		Negative	Comments Submitted
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		None	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Joe Spencer		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 316 of 316 entries

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Survey Report

Survey Details

Name 2007-06 System Protection Coordination | PRC-027-1 & PRC-001-1.1(ii)

Description

Start Date 4/1/2015

End Date 5/15/2015

Associated Ballots

2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) IN 1 ST

Survey Questions

See the Unofficial Comment Form on the Project Page for additional background information.

If you would like to bypass taking the survey, click the radio button and scroll down to submit the survey.

This will allow you to view Social Survey and agree / disagree with an already posted comment using the “thumbs up / thumbs down” feature.

Submitting a “thumbs up / thumbs down” on another entity's comment enables a negative vote to count in the calculation of consensus.

I want to bypass taking the survey

1. Do you agree that Parts 1.1 through 1.5 of Requirement R1 are the essential elements of a successful coordination process? Are there others that should be included? If not, please provide the basis for your disagreement and any proposed revisions or additions.

Yes

No

2. Do you agree with the proposed Measures? If not, please provide the basis for your disagreement and your proposed revisions.

Yes

No

3. Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.

Yes

No

4. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Responses By Question

See the Unofficial Comment Form on the [Project Page] for additional background information.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lynda Kupfer - Puget Sound Energy, Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Malloy - Idaho Falls Power - 3 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Stephenson - Great River Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jim Nail - City of Independence, Power and Light Department - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alshare Hughes - Luminant - Luminant Generation Company LLC - 4,5,6 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Terrill - Luminant - Luminant Generation Company LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - PPL NERC Registered Affiliates - 1,3,5,6 - MRO,WECC,NPCC,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 Oxy - Occidental Chemical, 7, Greaff Venona

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Venona Greaff - Oxy - Occidental Chemical - 7 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 2 Colorado Springs Utilities, 5, Brimhall Kaleb
Colorado Springs Utilities, 1, Speer Shawna

Dislikes: 0

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4
James McFall, Modesto Irrigation District, 3, 6, 4

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - Public Service Enterprise Group - 1,3,5,6 - NPCC,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Russ Schneider - Flathead Electric Cooperative - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0	
Dislikes:	0	

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0	
Dislikes:	0	

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	2	Nebraska Public Power District, 5, Schmit Don Nebraska Public Power District, 3, Eddleman Tony
Dislikes:	0	

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - Richard Hoag On Behalf of: Cindy Stewart, FirstEnergy - FirstEnergy Corporation, 1, 3

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Thorne - PHI - Potomac Electric Power Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 Colorado Springs Utilities, 1, Speer Shawna

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Morgan - Colorado Springs Utilities - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

manon paquet - manon paquet On Behalf of: Roger Dufresne, Hydro-Qu?bec Production, 1, 5

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name: PRC-027-1_Unofficial_Comment_Form_04012015_May14.doc

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 OGE Energy - Oklahoma Gas and Electric Co., 5, Staples Leo

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name: HYDRO ONE NETWORKS INC PRC-027-1_Unofficial_Comment_Form_04012015.docx

Likes: 1 Hydro One Networks, Inc., 3, Malozewski Paul

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Bee - Exelon - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Vince Catania - Exelon - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dave Carlson - Exelon - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leo Staples - OGE Energy - Oklahoma Gas and Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brown - Santee Cooper - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lewis Pierce - Santee Cooper - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

James Poston - Santee Cooper - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Fair - Colorado Springs Utilities - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

If you would like to bypass taking the survey, click the radio button and scroll down to submit the survey.

This will allow you to view Social Survey and agree / disagree with an already posted comment using the "thumbs up / thumbs down" feature.

Submitting a "thumbs up / thumbs down" on another entity's comment enables a negative vote to count in the calculation of consensus.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lynda Kupfer - Puget Sound Energy, Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Malloy - Idaho Falls Power - 3 - WECC

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Stephenson - Great River Energy - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jim Nail - City of Independence, Power and Light Department - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alshare Hughes - Luminant - Luminant Generation Company LLC - 4,5,6 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Terrill - Luminant - Luminant Generation Company LLC - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - PPL NERC Registered Affiliates - 1,3,5,6 - MRO,WECC,NPCC,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 Oxy - Occidental Chemical, 7, Greaff Venona

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Venona Greaff - Oxy - Occidental Chemical - 7 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4
James McFall, Modesto Irrigation District, 3, 6, 4

Error: Subreport could not be shown.

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - Public Service Enterprise Group - 1,3,5,6 - NPCC,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Russ Schneider - Flathead Electric Cooperative - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - Richard Hoag On Behalf of: Cindy Stewart, FirstEnergy - FirstEnergy Corporation, 1, 3

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Thorne - PHI - Potomac Electric Power Co. - 1 -

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Shawna Speer - Colorado Springs Utilities - 1 -

Selected Answer:	I want to bypass taking the survey
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Charles Morgan - Colorado Springs Utilities - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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manon paquet - manon paquet On Behalf of: Roger Dufresne, Hydro-Qu?bec Production, 1, 5

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Error: Subreport could not be shown.

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 Santee Cooper, 3, Poston James

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 OGE Energy - Oklahoma Gas and Electric Co., 5, Staples Leo

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Bee - Exelon - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Vince Catania - Exelon - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dave Carlson - Exelon - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 Hydro-Qu?bec TransEnergie, 1, Phan Si Truc

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leo Staples - OGE Energy - Oklahoma Gas and Electric Co. - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brown - Santee Cooper - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lewis Pierce - Santee Cooper - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

James Poston - Santee Cooper - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Fair - Colorado Springs Utilities - 6 -

Error: Subreport could not be shown.

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

1. Do you agree that Parts 1.1 through 1.5 of Requirement R1 are the essential elements of a successful coordination process? Are there others that should be included? If not, please provide the basis for your disagreement and any proposed revisions or additions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lynda Kupfer - Puget Sound Energy, Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: No

Answer Comment:

1. Is it not clear what the differences between part 1.2 and 1.3 are.
2. Does 1.2 mean a Protection System settings review in a specific affected area due to some specific System changes? What kind of system changes (and how significant the changes are) would constitute a protection setting review?
3. Is 1.3 meant for a periodic overall review of the existing entity-designated protection system settings of all the BES elements that an entity owns? Based on 1.3, an entity has to do a fault study on every BES bus to determine if the fault current deviates by 15%. If the entity finds that the fault current at some of the BES busses indeed deviates by more than 15%, does the entity need to review the protection settings in the immediate area only or otherwise?

Document Name:

Likes: 0

Dislikes: 0

Richard Malloy - Idaho Falls Power - 3 - WECC

Selected Answer: No

Answer Comment:

It is confusing to the industry to have several standards pertaining to setting coordination. Why would NERC add a standard pertaining specifically to faults rather than simply revising the PRC-001 standard. Further there are several standards related to settings for generation ride through to disturbances, and UFLS settings requirements that muddy the waters of understanding and efforts required under this draft PRC-027.

Requirement (R4) of PRC-001 required the Transmission Owner to coordinate with Generation Owners on Transmission line settings. It is our belief that the TO should still be taking the lead in coordination in the draft PRC-027 requirements language.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Stephenson - Great River Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer: No

Answer Comment:

We agree with Parts 1.2, 1.3 and 1.5 of Requirement R1, but disagree with Parts 1.1 and 1.4.

Part 1.1 is not results-based; it is overly prescriptive and an inherent and necessary element for developing new or revised Protection System settings. We suggest to remove it as it does not any value to Requirement R1.

R1.2. The wording in the draft standard is confusing. Suggest the following wording: "A review of the affected Protection System settings due to System changes as determined by the entity's process."

- The study should clearly mention that System changes will reset baseline for Fault current studies.

- The rationale box for R1.2 is open ended and may leave the impression that every change, even minor ones, will be considered a System change and be subject to an audit. The standard should better define "System changes."

Part 1.4 is unclear and unnecessary. It is unclear as to what constitutes a "quality review", and how is it measured. It is not necessary to perform any QR. If the intent is to have this included in the process document to ensure

new or revised protection system settings are properly coordinated, then this part should be revised to say, e.g.:

1.4 A check list to verify that the development of the new or revised protection system settings is coordinated among affected entities and that the proposed settings can achieve the intent of fault clearing prior to implementation.

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Wisconsin Electric supports the standard in concept but believes it needs more specificity. While in general we appreciate flexibility that the SDT wrote into the standard, we have seen that this leads to inconsistencies in application. Specifically, R1 states that entities shall establish a process for developing settings. It is very open ended and will be very subjective to evaluate.

We also think the timeline for activities needs to be better defined. For example, if in R1.3 you find that there has been a 15% deviation in fault current how long do you have to perform the review?

For R1.5 we need to communicate the settings to other entities and they shall review them. Does this need to be done before they are implemented or does the methodology in the procedure almost guarantee coordination? For R1.5 we would like to see in the measures what the acceptable evidence would be.

It was mentioned on the webinar that this is a forward looking standard and that no coordination review needs to be done unless triggered by R1.2 or R1.3. This should be specifically spelled out in the standard.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: No

Answer Comment:

1) Is it not clear what the differences between part 1.2 and 1.3 are.

2) Does 1.2 mean a Protection System settings review in a specific affected area due to some specific System changes? What kind of system changes (and how significant the changes are) would constitute a protection setting review?

3) Is 1.3 meant for a periodic overall review of the existing entity-designated protection system settings of all the BES elements that an entity owns? Based on 1.3, an entity has to do a fault study on every BES bus to determine if the fault current deviates by 15%. If the entity finds that the fault current at some of the BES busses indeed deviates by more than 15%, does the entity need to review the protection settings in the immediate area only or otherwise?

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jim Nail - City of Independence, Power and Light Department - 5 -

Selected Answer: No

Answer Comment:

Subrequirement 1.4 is too prescriptive. It has the nature of an internal control rather than a compliance process. Internal controls should be left to the discretion of the Entities, not included as auditable requirements. While we understand FERC's concern with MisOperations caused by incorrect settings, that can be addressed as part of the mitigation plan of entities who fail to properly maintain their protection systems and should not be reason to dictate internal controls to the rest of the industry.

Document Name:

Likes: 0

Dislikes: 0

Alshare Hughes - Luminant - Luminant Generation Company LLC - 4,5,6 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Terrill - Luminant - Luminant Generation Company LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The requirement to coordinate protective relay settings has existed since the first power systems were built. BC Hydro, like all utilities, has been coordinating their protection systems as part of their normal practice and has a process for setting development, review and implementation on its protection systems. While the requirements in Draft 5 of PRC-027-1 are not substantially different than standard industry practice, proving annual compliance with these requirements (to the satisfaction of lawyers) will impose a large administrative burden. The original focus of PRC-001 made sense in that there are always communications and data gathering issues that make coordinating protection systems across different utilities more challenging than coordinating within one's own system. The new draft standard focuses too much of the utility's time and effort on proving compliance on a process that typically works well, which reduces the amount of time and effort that can be spent on areas where more time and money should be spent.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

AEP believes that R 1.2 is sufficient to cover coordination of all internal protection systems. As a result, R1 part 1.3 should be limited only to Protection Systems applied to BES Elements that electrically join Facilities owned by separate functional entities. This would require AEP to set baselines and keep track of fault currents at approximately 1800 buses. AEP has a process to review area coordination when system changes are made. All settings in an area that are affected by the change are reviewed and revised as necessary. Because of this process, it is not likely that any reviews of internal protection systems would result due to changes in fault current. Thus, this requirement would become an administrative burden without any reliability benefit for internal protection systems.

It is reasonable to require a periodic review on protection systems applied to interconnecting elements, because an entity does not have knowledge of what changes are made by another entity that may affect protection system coordination.

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - PPL NERC Registered Affiliates - 1,3,5,6 - MRO,WECC,NPCC,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The PPL NERC Registered Affiliates believe that the requirements under PRC-027 for TO/TOP are acceptable but the inclusion of GOs in the applicability of this standards, as outlined below, is problematic. Without resolution of this concern PPL is unwilling to support the approval of this proposal.

The purpose of PRC-027-1 is to ensure that “Protection System components operate in the intended sequence during Faults,” but there is no sequencing of Protection System components within a generation plant. There is need for GOs to coordinate some Protection System settings with the TO, however, but this activity is already covered by other standards.

We raised these points in NERC’s 4/27/15 webinar on PRC-027-1, but the presenters did not address the issue and instead simply stated that GO-TO coordination of loadability relays is needed, adding that this task is described in various technical publications. We agree, and prominent among these sources is, “Coordination of Generator Protection with Generator Excitation Control and Generator Capability,” which is referenced on p.5 of PRC-019 and was specifically written for PRC-019. It covers GO-TO loss-of-field coordination in part V of the paper, and generator phase-backup coordination in part VI. That is, PRC-019-1 covers the supposed gap that PRC-027-1 is attempting to address.

We also disagree with the statement made during the webinar that PRC-025-1 deals only with acceptable setting ranges for loadability relays and not coordination. The “Background” section of this document makes it clear that the standard intends to accomplish coordination, and the tables and example calculations spell-out in detail how this is to be done.

The need mentioned on p.13 PRC-027 to communicate generator and GSU impedance changes to the TO is meanwhile already accomplished by MOD-010-0 (MOD-032-1 after 7/1/15). Supplemental GO relay-setting issues are covered by the existing standards cited on p.3 of PRC-027-1, and R2.1 of PRC-001-2 presents a catch-all mandate that “Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.”

PRC-027-1 is consequently redundant for GOs, nor is there any need to change PRC-001. Enacting PRC-027-1 in its present state would cause confusion, not close gaps. An entity believing that coordination of loadability relays will not be required until PRC-027-1 becomes effective may be cited for PRC-019-1 and PRC-025-1 violations, for example.

The SDT should carefully study existing standards and trim PRC-027-1 accordingly, including making it not applicable to GOs.

The quality review of PRC-027-1 R1.4 should also be deleted. We agree that entities should apply a prepared-by-reviewed-by-approved-by process in developing relay settings, but this is standard industry practice for all calculations and procedures. It is therefore unclear what new and special quality control activities justify setting PRC-027-1 apart from all other NERC standards in this respect.

Document Name:	
Likes:	0
Dislikes:	0

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5 -

Selected Answer: No

Answer Comment:

Ingleside Cogeneration (ICLP) believes that the scope of PRC-027-1 Draft 5 greatly extends beyond the concern initially raised by FERC staff. In our view, they are simply pointing out a similarity in purpose and structure between Fault relays protecting long transmission lines located fully within a single TO's footprint and those that interconnect to a neighboring TO, GO, or DP. Instead, the project team requires some level of disposition for every BES Protection System that reacts to a Fault.

Although we appreciate the flexibility allowed under Part 5.3 to designate the Protection Systems that are to be included in any one review, ICLP believes that CEAs will question any omission based upon design and/or susceptibility to changes in Fault current.

Document Name:

Likes: 1 Oxy - Occidental Chemical, 7, Greaff Venona

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer: No

Answer Comment:

Tacoma Power generally agrees that Parts 1.1 through 1.5 of Requirement R1 are elements of a successful coordination process, but Tacoma Power does not agree that they are all 'essential.' Tacoma Power's specific comments follow.

Part 1.1. Tacoma Power believes that Part 1.1 is implied by the term 'review' in Parts 1.2, 1.3, and 1.5. Furthermore, as written, Part 1.1 may be difficult to audit under Requirement R2. Therefore, Tacoma Power recommends eliminating Part 1.1.

Part 1.2. Tacoma Power recommends the following verbiage for Part 1.2: "A method to review and, if necessary, update Protection System settings due to System and/or Protection System changes." Tacoma Power believes that Part 1.2 should focus on requiring a method, not the review itself, and that updates may be needed. Furthermore, as written in the current draft, Part 1.2 only refers to System changes, but an entity could change a Protection System without a System change, and this latter change could still require cascading Protection System changes. (If Part 1.4 is eliminated (see subsequent comments for Part 1.4), then the following verbiage is recommended for Part 1.2: "A method to review and, if necessary, update Protection System settings due to, and prior to implementation of, System and/or Protection System changes.")

Part 1.3. Tacoma Power generally supports Part 1.3. However, for periodic Fault current studies, no timeframe for reviewing existing entity-designated Protection System settings is specified following identification of a 15 percent or greater deviation in Fault current. To be consistent with the periodic review of Protection System settings, it is recommended that the interval for performing Fault studies, plus the timeframe to subsequently review Protection System settings, equals six calendar years, which means that Fault current studies should be performed more frequently than every six calendar years.

Part 1.3. Tacoma Power recommends changing “A review of...” to “A method to review and, if necessary, update...”

Part 1.3. Tacoma Power also recommends changing “A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground)...” to “A deviation in Fault current (either three-phase or phase-to-ground) greater than 15%...,” which should address some concerns that, for example, a 14.6% could be interpreted by an auditor as 15% due to rounding.

Part 1.3. Tacoma Power believes that clarification will be needed as to whether (1) an entity can choose between three-phase Fault current and phase-to-ground Fault current as a trigger or (2) an entity must use the greater change in the two Fault current values as a trigger.

Part 1.4. While it is a best practice, Tacoma Power does not believe that Part 1.4 is ‘essential.’ That said, if the drafting team elects to leave Part 1.4, Tacoma Power has the following comments. (1) Although rare, exceptions should be permitted (a) under bonafide emergencies and (b) when Protection System settings need to be altered during the implementation (commissioning) phase, provided that a follow-up review of quality is performed promptly (e.g., within 30 calendar days). (2) Tacoma Power recommends changing “A quality review of...” to “A review of the quality of...” (If the drafting team elects to eliminate Part 1.4, then Tacoma Power recommends that the verbiage in Part 1.2 be modified (see preceding comments for Part 1.2).)

Part 1.5. Tacoma Power generally supports Part 1.5. However, Tacoma Power believes that an exception to Part 1.5 should be granted when one engineering workgroup is responsible for Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, especially when those functional entity are part of the same company.

Part 1.5. Tacoma Power recommends a fourth sub-part: “Communicate with the other functional entities that the Protection System settings were implemented, including any alterations to Protection System settings that needed to be made during implementation.” This additional sub-part helps to close the loop.

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Venona Greaff - Oxy - Occidental Chemical - 7 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Seattle City Light, like many urban utilities, has very short transmission lines that require the use of communication-assisted (pilot) schemes in order to provide proper sectionalizing (coordination) of the transmission system during a fault event. Guidance is not provided in the latest version of the standard for the coordination of pilot schemes and their backup relays (67N, e.g.). The 67N relays, located at the different buses, cannot be coordinated on our system per proposed PRC-027. To address this matter, Seattle recommends allowing miscoordination of the back-up scheme, under the standard, as long as the back-up scheme is only enabled whenever the communication-assisted (pilot) scheme has failed.

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The NSRF commends the SDT for the concept employed in the standard as we believe it addresses FERC's concerns and minimizes the impact on the Registered Entities. We do however have some specific comments that we believe should be addressed:

R1 states: *The **process** shall include:* , in R1.5, it states: ***procedures** to:*

The NSRF recommends that the word "procedures" be removed from R1.5.

R1.1: The requirement should be revised to "A method to review and update (when required) the information…" The industry has had past issues with do you need to update a process if there are no changes noted during your review. This addition will allow Entities to *review* and not *update* when no changes are required.

The second bullet of R1.3 states a Registered Entity must perform a "Periodic Review of Protection System settings" at a maximum interval not to exceed 6 years. In the Rational Box the SDT stated they chose 6 years because it corresponded to the maintenance period for certain relays. The NSRF believes this unfairly impacts owners of protective devices where the maintenance period is longer. Our recommendation is to revise the requirement to correspond to the maintenance period of the type of relay referenced in PRC-005. This way the setting comparison required by PRC-005 and the setting review can be accomplished at the same time making it more efficient. With thousands of Protection System relays to review every 6 years, there would be a large burden upon entities to outsource this activity. In our opinion there is not a large amount of risk in extending the interval because entities already review Protection System impacts in the areas where known construction activities change the electrical system. The second bullet of R1.3 should be revised to state "**Periodic Review of Protection Settings:** A time interval not to exceed that referenced in PRC-005 for a particular Protection System device."

Section 1.3 should be re-written to make it clear that an entity can conduct a condition based review within a given maximum time interval **and** as long as the conditions do not warrant a Protection System settings review, the comparison of the conditions to a baseline are satisfactory to prove compliance. If the conditions indicate a review should be conducted, then additional time should be granted to allow for the Protection System settings review.

The rationale for Section 1.3 should be carefully written as it states that a current differential protection scheme may not need to be included because changes in fault current will not affect the coordination of this system. The concern is that fault currents could increase to a point where CT saturation would prevent the current differential protection from operating as designed and therefore should be reviewed just like any other current sensitive protection system.

R1 section 1.4 should add clarity as to whether it applies to new or revised Protection System settings similar to R1 sections 1.1 and 1.5.

R1 section 1.5 needs to be re-written as it is fragmented and should state that the entity needs to establish a procedure and the procedure shall include the items covered under sections 1.5.1, 1.5.2 and 1.5.3. Suggested wording would be ". . . Distribution Providers), shall establish procedures to include the following items at a minimum:"

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

R1.1. “A method to review and update the information required to develop new or revised Protection Sytem settings” requires entities to develop a process to review information used in two studies: Short Circuit study and Protective Device Coordination study. R1.1. only addresses the ‘What’ but does not address the ‘When’. The ‘When’ for the review of the information used in the Protective Device Coordination study is addressed in R1.2 and R1.3; however, the ‘When’ for the review of information used in the Short Circuit study is never addressed. From our understanding, the only evidence that is required for this standard with respect to the review of information used for the Short Circuit study will be documentation of the ‘What’; no evidence is required of when it was followed.

Also, the word “review” in R1.1 is confusing and suggests going back in time. Suggest revised wording as follow: “A method to update the information required to develop new or revised Protection System settings.”

R1.2. The wording in the draft standard is confusing. Protection System settings are not affected by System changes. Suggest the following wording: “A review of the affected Protection System settings due to System changes as determined by the entity’s process.”

- It was mentioned in the Webinar on April 27, 2015 that System changes will reset baseline for Fault current studies. If this is the case, then it should be made clear in the standard.

- Proving system changes will be onerous. The rationale box for R1.2 is open ended and may leave the impression that every change, even minor ones, will be considered a System change and be subject to an audit. The standard should better define “System changes.”

R1.3. The last part of the description for “Periodic Fault current studies” is confusing. Suggest the wording be changed to the following: “… at the bus under study, and this Fault Current analysis evaluated in a time interval not to exceed six calendar years, or”

With regard to the discussion on R1.1.3 at the Webinar on April 27, 2015, it was stated that once the standard is adopted Utilities have 12 months to establish their fault current baseline, if using the Periodic Fault Current Study method or 6 years to perform their next Periodic review of Protection System settings if using that method of compliance. Those time frames should be spelled out in the document, especially the 12 months because it does not appear anywhere. Perhaps the best place for this is in the Implementation Plan.

Regarding Part 1.3, the first bullet, if the entity identifies a Fault current change greater than 15 percent, the periodic review should apply only to those buses identified as having a 15 percent or greater deviation in Fault current in the study and the connected buses one station away from those buses. Footnote 1 can be revised to:

Based on the Protection System design and/or susceptibility to changes in Fault current, applicable entities (Transmission Owners, Generator Owners, and Distribution Providers) will designate what Protection Systems must be included in the review(s) to ensure these Protection Systems continue to operate in the intended sequence during Faults. For buses where the Fault current changed by 15 percent or greater, the Protection Systems will be those applied at the bus with the change in Fault current, and connected stations one bus away.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment:

Parts 1.1 through 1.4 have nothing to do with coordination with neighbors as previously covered by PRC-001 R3 and R4. They describe an internal process for protection design that is outside the scope of coordination with neighbors. Delete Parts 1.1 through 1.4.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: No

Answer Comment:

More clarification would be helpful concerning the term "entity-designated Protection System settings". It appears that these settings that are considered to be susceptible to fault current changes. Providing a listing of susceptible Protection System setting types applicable to the GO, TO and DP would insure that nothing is missed in the review.

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer: No

Answer Comment:

See comments is question #4.

Document Name:

Likes: 2 Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4, James McFall, Modest
Colorado Springs Utilities, 3, Morgan Charles

Dislikes: 0

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4
James McFall, Modesto Irrigation District, 3, 6, 4

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

While ATC agrees with the elements of a successful coordination process, we do not agree with the overall approach to the draft standard. It appears to be missing an element that incorporates a feedback loop to measure improvement.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - Public Service Enterprise Group - 1,3,5,6 - NPCC,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We generally agree, but we have concerns with the Parts themselves, as explained in #3 and #4 below.

Document Name:

Likes: 0

Dislikes: 0

Russ Schneider - Flathead Electric Cooperative - 4 -

Selected Answer: No

Answer Comment:

I do not feel that 1.5.2 is necessary to demonstrate coordination. Could be aligned with 1.5.3 and state simply "Verify that no coordination issues were identified....

In adition, not sure that 1.2 or 1.4 add value to the standard as they should be covered in 1.3.

Document Name:

Likes: 0

Dislikes: 0

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1 -

Selected Answer: Yes

Answer Comment:

We generally agree, but we have concerns with the Parts themselves, as explained in #3 and #4 below.

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: No

Answer Comment:

Generally the parts 1.1 to 1.4 are essential elements for successful coordination. Part 1.5 creates unnecessary complications when phasing in projects or dealing with other entities that are not responsive in a timely fashion. Part 1.5 should be deleted since it can implicate a utility that is dealing with slow to respond interconnecting neighbors. There are utilities that will respond but may not respond in a timely manner. This puts all entities unfairly under scrutiny. If Part 1.4 is followed then 1.5 is not needed. This will eliminate implicating the responsible entity when dealing with slow to respond interconnecting neighbors and avoid tracking complex timelines with multiphase projects that may not have simple implementation dates. One scenario that can cause concern can be with generator owners that may not have their own engineering staff but must hire external staff if a coordination study is required. This process issue is not always under the control of the requesting entity and can create some issues with part 1.4 as well. In this sense it is a good thing if we can show seeking concurrence is acceptable for compliance even if we cannot show a response to a request.

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: No

Answer Comment:

Refer to the MRO NSRF comments.

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer: No

Answer Comment:

We agree with Parts 1.2, 1.3 and 1.5 of Requirement R1, but disagree with Parts 1.1 and 1.4.

Part 1.1 is not results-based; it is overly prescriptive and an inherent and necessary element for developing new or revised Protection System settings. We suggest removing Part 1.1 as it does not any value to Requirement R1.

R1.2. The current wording in the draft standard is confusing. We would suggest the following alternative wording: "A review of the affected Protection System settings due to System changes as determined by the entity's process."

- **The study should clearly mention that System changes will reset the baseline for future Fault current studies.**

- **The rationale box for R1.2 is open ended and leaves the impression that every change, even minor ones, will be considered a System change and be subject to an audit. The standard should better define "System changes."**

Part 1.4 is unclear and unnecessary. It is unclear as to what constitutes a "quality review" (QR), and how is it measured. Furthermore, it is not necessary to perform any QR. If the intent is to have this included in the process document to ensure new or revised protection system settings are properly coordinated, then this part should be revised to say, e.g.:

1.4 A check list to verify that the development of the new or revised protection system settings is coordinated among affected entities and that the proposed settings can achieve the intent of fault clearing prior to implementation.

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: No

Answer Comment:

Entergy is concerned with elements of Parts 1.1 through 1.5 of Requirement R1.

Entergy is concerned that requirement R.1.3 does not adequately identify the methodology for establishing “baseline Fault current values.” Entergy would suggest the inclusion in requirement R1.3 of additional language on baseline Fault current values from bottom of page 13 and top of page 14 in the Supplemental Material document, as follows:

The baseline can be the Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect. These baseline Fault current values can be at the bus level or at the individual Element level. When performing the periodic Fault current comparison, the entity would continue to compare actual Fault current values gathered during the review against the originally established baseline values until a condition occurs that necessitates the establishment of a new baseline.

Entergy disagrees with the inclusion of the language “prior to implementation” in Requirement R1.5.3 without a means to compel a timely response to the request for coordination . Requirement R1.5.3 provides as follows:

1.5.3. Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation.

Based on experience, there are situations in which a Transmission Owner has submitted relay settings information to a coordinating party and the coordinating party has not responded or is incapable of assessing the impact of the change being coordinated. A lack of coordinating party response puts the Transmission Owner at risk of non-compliance with Requirement 1.5.3. Entergy recommends that Requirement 1.5.3 be revised to (1) require the coordinating party to respond to Transmission Owner within thirty (30) days after receipt of notification of proposed Protection System settings, provided that in the event of an Emergency, the coordinating party shall be required to respond to Transmission Owner as soon as practicable under the circumstances, and (2) in the event the coordinating party does not respond to the Transmission Owner's request for coordination in a timely manner, permit the Transmission Owner to assess and implement Protection System settings without acknowledgement from the coordinating party, subject to the requirement that the Transmission Owner provide prior notice to the coordinating party of its intent to implement its proposed Protection System settings..

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - Richard Hoag On Behalf of: Cindy Stewart, FirstEnergy - FirstEnergy Corporation, 1, 3

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

FE's primary concern relates to what is required of the GO to be able to comply with R1 which states the TO, GO and DP "… establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults." The GO, operates the units essentially as isolated BES elements. The term "sequence" infers it is referring to the BES as a whole, at least with regard to interconnected elements, which would then mean we need a joint process with the TO. The GO is not in a position to make that happen, nor should the GO have primary responsibility. This should be a TO responsibility, with GO providing settings as requested by TO, and GO changing settings as requested/instructed by the TO.

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Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer: No

Answer Comment:

GTC is in support of the SERC Comments:

While the SERC PCS agrees that PRC-027 is needed, and with the methodology within draft 5, the following items must be clarified for us to support it:

1) In R1 1.2 replace '…affected by System changes' with '…affected by Bulk Electric System changes' because the NERC Glossary 'System' definition includes distribution. NERC BES Definition phase 2 process is very rigorous and includes the Elements of significance in this coordination work.

2) R1 1.3 Footnote 1 and the concept of excluding 'entity-designated' Protection System settings is troublesome. The SDT explained that footnotes are enforceable in their 4/27/2015 Webinar, and that entities will have to justify such designations. R1 1.3 Footnote 1 text should be moved into the body of the requirement, eliminating the footnote, and clarity be given on what entities would need to do to justify the Protection Systems they are designating.

3) The existing Protection System settings have been and are already coordinated. We agree with the SDT 4/27/2015 Webinar statement that PRC-027 'draws a line in the sand and goes forward from there.' Please include a statement somewhere in the R1 Rationale that memorializes the validity of

existing Protection System settings as a baseline. We recommend including this statement in the R1 part 1.3 first bullet,

Periodic Fault current studies, rationale. ‘Protection System settings existing when the Fault Current baseline is established are accepted as being coordinated consistent with the Purpose of this standard. This acknowledges that the vast majority of entities have a long history and much experience coordinating their Protection Systems. On the other hand, if an entity is unable or unwilling to make this assertion, then that entity needs to explain the second bullet, *Periodic review of Protection System settings,* in its R1 process is its means of proving coordination of existing settings.’

4) In some companies the same protective relaying group performs coordination work for separate functional entities, so the R1 1.5 communication is often in the protection setting notes themselves. Please add ‘The drafting team also recognizes there are situations where the same protective relaying group performs coordination work for separate functional entities, and in such cases the R1 Part 1.5 communication is handled via internal written documentation.’ We suggest adding in the Supplemental Material on page 15 just above Requirement R2.

Document Name:

Likes: 0

Dislikes: 0

David Thorne - PHI - Potomac Electric Power Co. - 1 -

Selected Answer: Yes

Answer Comment:

PHI agrees that the information identified in parts 1.1 through 1.5 of Requirement R1 cover the essential elements needed to develop and ensure coordination of BES protective relaying schemes.

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

CSU agrees with SMUD's Comments concerning a potentially more effective approach to PRC-027.

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Morgan - Colorado Springs Utilities - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

manon paquet - manon paquet On Behalf of: Roger Dufresne, Hydro-Qu?bec Production, 1, 5

Selected Answer: Yes

Answer Comment:

Part 1.5 requires that separate functional entities communicate their proposed Protection System settings with other functional entities. Should there be a proposed time limit to get a response from the other entity to ensure that there are no delays in addressing coordination issues prior to implementation?

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

R1.5 remains ambiguous in terms of which entities are obligated to perform the tasks, and under which circumstances. Is the intent, as written, that it only applies where interconnected Facilities do not have the same ownership? Is the applicability based on the functional entity category irrespective of Facility ownership (i.e., to ensure intra-company communications)? The requirement needs to be revised to provide absolutely certainly in terms of which entities have the obligations.

Document Name:

Likes: 0

Dislikes: 0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

While the SERC PCS agrees that PRC-027 is needed, and with the methodology within draft 5, the following items must be clarified for us to support it:

1) In R1 1.2 replace '…affected by System changes' with '…affected by Bulk Electric System changes' because the NERC Glossary 'System' definition includes distribution. NERC BES Definition phase 2 process is very rigorous and includes the Elements of significance in this coordination work.

2) R1 1.3 Footnote 1 and the concept of excluding 'entity-designated' Protection System settings is troublesome. The SDT explained that footnotes are enforceable in their 4/27/2015 Webinar, and that entities will have to justify such designations. R1 1.3 Footnote 1 text should be moved into the body of the requirement, eliminating the footnote, and clarity be given on what entities would need to do to justify the Protection Systems they are designating.

3) The existing Protection System settings have been and are already coordinated. We agree with the SDT 4/27/2015 Webinar statement that PRC-027

'draws a line in the sand and goes forward from there.' Please include a statement somewhere in the R1 Rationale that memorializes the validity of existing Protection System settings as a baseline. We recommend including this statement in the R1 part 1.3 first bullet, *Periodic Fault current studies,* rationale. 'Protection System settings existing when the Fault Current baseline is established are accepted as being coordinated consistent with the Purpose of this standard. This acknowledges that the vast majority of entities have a long history and much experience coordinating their Protection Systems. On the other hand, if an entity is unable or unwilling to make this assertion, then that entity needs to explain the second bullet, *Periodic review of Protection System settings,* in its R1 process is its means of proving coordination of existing settings.'

4) In some companies the same protective relaying group performs coordination work for separate functional entities, so the R1 1.5 communication is often in the protection setting notes themselves. Please add 'The drafting team also recognizes there are situations where the same protective relaying group performs coordination work for separate functional entities, and in such cases the R1 Part 1.5 communication is handled via internal written documentation.' We suggest adding in the Supplemental Material on page 15 just above Requirement R2.

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 3, Poston James

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

While the SERC PCS agrees that PRC-027 is needed, and with the methodology within draft 5, the following items must be clarified for us to support it:

1) In R1 1.2 replace '…affected by System changes' with '…affected by Bulk Electric System changes' because the NERC Glossary 'System' definition includes distribution. NERC BES Definition phase 2 process is very rigorous and includes the Elements of significance in this coordination work.

2) R1 1.3 Footnote 1 and the concept of excluding 'entity-designated' Protection System settings is troublesome. The SDT explained that footnotes are enforceable in their 4/27/2015 Webinar, and that entities will have to justify such designations. R1 1.3 Footnote 1 text should be moved into the body of the requirement, eliminating the footnote, and clarity be given on what entities would need to do to justify the Protection Systems they are designating.

3) The existing Protection System settings have been and are already coordinated. We agree with the SDT 4/27/2015 Webinar statement that PRC-027 'draws a line in the sand and goes forward from there.' Please include a statement somewhere in the R1 Rationale that memorializes the validity of existing Protection System settings as a baseline. We recommend including this statement in the R1 part 1.3 first bullet, *Periodic Fault current studies,* rationale. 'Protection System settings existing when the Fault Current baseline is established are accepted as being coordinated consistent with the Purpose of this standard. This acknowledges that the vast majority of entities have a long history and much experience coordinating their Protection Systems. On the other hand, if an entity is unable or unwilling to make this assertion, then that entity needs to explain the second bullet, *Periodic review of Protection System settings,* in its R1 process is its means of proving coordination of existing settings.'

4) In some companies the same protective relaying group performs coordination work for separate functional entities, so the R1 1.5 communication is

often in the protection setting notes themselves. Please add ‘The drafting team also recognizes there are situations where the same protective relaying group performs coordination work for separate functional entities, and in such cases the R1 Part 1.5 communication is handled via internal written documentation.’ We suggest adding in the Supplemental Material on page 15 just above Requirement R2.

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 3, Poston James

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We agree with Parts 1.2, 1.3 and 1.5 of Requirement R1, but disagree with Parts 1.1 and 1.4.

Part 1.1 is not results-based; it is overly prescriptive and an inherent and necessary element for developing new or revised Protection System settings. We suggest to remove it as it does not add any value to Requirement R1.

Part 1.4 is unclear and unnecessary. It is unclear as to what constitutes a “quality review” as this term is confused with that part of the standards development process with the same name. If the intent is to have this included in the process document to ensure new or revised protection system settings are properly coordinated, then this part should be revised to say, e.g.:

1.4 A check list to verify that the development of the new or revised protection system settings is coordinated among affected entities and that the proposed settings can achieve the intent of fault clearing prior to implementation.

Note - These SRC comments represent a consensus of the ISOs/RTOs with the exception of ERCOT.

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 1 OGE Energy - Oklahoma Gas and Electric Co., 5, Staples Leo

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. agrees with NPCC on the following.:

1) Under R1.1, “A method to review and update the information required to develop new or revised Protection System settings” requires entities to develop a process to review information used in two studies: Short Circuit study and Protective Device Coordination study. The ‘When’ for the review of information used in the Short Circuit study has not been addressed. R1.1. addresses the ‘What’ but does not address the ‘When’. The ‘When’ for the review of the information used in the Protective Device Coordination study is addressed in R1.2 and R1.3. Therefore, the only evidence that is required with respect to the review of information used for the Short Circuit study will be documentation of the ‘What’; no evidence is required of “When” it was followed.

2) Further, in R1.1, the word “review” suggests going back in time. It is suggested that the wording is revised to read as follows: “A method to update the information required to develop new or revised Protection System settings.”

3) The wording for R1.2 is unclear. Protection System settings are not affected by System changes. It is suggested that the following wording be considered instead: “A review of the affected Protection System settings due to System changes as determined by the entity’s process.”

4) It was mentioned during the Webinar on April 27, 2015 that System changes will reset the baseline for Fault current studies. If this is the case, it should be explicitly stated in the standard.

5)In the rationale box for R1, Part 1.2 is open-ended and may leave the impression that every change, even minor ones, will be considered a System change and be subject to an audit. Therefore, the standard should specifically define “System changes.”

6) The last part of the description in R1.3 for “Periodic Fault current studies” is unclear. It is suggested that the wording under the first bullet in R1.3 be changed to read the following: “… at the bus under study, and this

Fault Current analysis be evaluated at a time interval not to exceed six calendar years, or”

7) With regard to the discussion on R1.3 at the Webinar held on April 27, 2015, it was stated that once the standard is adopted, utilities would be given 12 months to establish their fault current baseline, if using the Periodic Fault Current Study method, or 6 years to perform their next Periodic review of Protection System settings if using the method of compliance which requires a Periodic review. These time frames should be spelled out in the document; in particular, the 12 months given to establish a fault current baseline, as it is not stated in the standard. These dates should be stated in the Implementation Plan as well.

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer: No

Answer Comment:

Please clarify R1.3. We believe the SDT intends to say that an entity must have a process to review protection system settings:

- First Bullet- Review Bus fault currents at least every six years. If review indicates that fault current has increased to 15% or more than baseline, then perform a settings review for relays associated with that bus.

- Second Bullet- Review relay settings at least every six years

- Third Bullet- Some combination of first two bullets.

If our understanding is correct, we propose a minor clarification to the first bullet in R1.3

· **Periodic Fault current studies:** A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the bus under study. The fault current must be evaluated periodically with the time interval not to exceed 6 years.

As a Generator, Part 1.3 of requirement R1 needs to be defined clearly from the GOs viewpoint stating if contribution by GO increases by 15%. It talks about a fault current at a Bus which is more appropriate for TO. GO's current contribution increases only when the Generators and Main Power transformers are replaced with machines with lower impedances. So the requirements should be tied with that rather than on a certain time.

Part 1.4 - Agree

Part 1.5.3: We remain concerned with the requirement as written. 1.5.3 is open to interpretation regarding how an entity addresses an identified coordination issue prior to implementation. As noted in the Supplemental Material, differences in Protection Philosophy, the actual risk of an unmitigated issue or the timing of a mitigation action are all areas where entities may disagree before the implementation of new settings. A change to 1.5.2 indicating that the communication between the coordinating entities should include the entities proposal for what or if any action they intend to take respecting an identified issue would be sufficient. This is consistent with the Supplemental Material explanation for Part 1.5.2

Document Name:

Likes: 0

Dislikes: 0

John Bee - Exelon - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Vince Catania - Exelon - 5 -

Selected Answer: No

Answer Comment:

See Exelon commnets as submitted by C Scanlon

Document Name:

Likes: 0

Dislikes: 0

Dave Carlson - Exelon - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer: No

Answer Comment:

1. Ambiguity exists with respect to what "coordination" is being addressed. This should be explicitly clarified. Part 1.5 addresses coordination of information with others necessary to determine proper settings on BES Protection Systems for facilities owned by two different entities, which is consistent with the context of the existing standard. However, Parts 1.1-1.4 pertain to an entity's internal process for developing, reviewing, and validating settings, which is not considered in the current standard and is not in the same coordination context as Part 1.5. As presented, parts 1.1 through 1.4 exceeds "what needs to be done" and ventures into the "how it needs to be done" which runs counter to the intent of the NERC standards and risk-based requirements. Parts 1.1 – 1.4 should be rewritten in a manner similar to Part 1.5 as follows:

Each Transmission Owner, Generator Owner, and Distribution Owner shall implement a documented process for developing and installing coordinated settings for its Protection Systems for BES Elements associated with solely-owned Facilities to ensure the Protection Systems operate in the intended sequence during Faults.

This approach would also result in the elimination of one of the requirements as the implementation piece is captured with the documented process aspect.

Although we wish Requirement R1 to be rewritten as discussed above, we have the following additional comments with regards to the language of the requirements as currently proposed:

2. To make the existing requirement language clearer, Requirement R1 should be amended to state "……develop settings for its BES Protection Systems to ensure they operate in the intended sequence……"

3. Soon to be implemented MOD-032-1 requires Transmission Owners (TO) and Generator Owners (GO) in R2 to submit short-circuit modeling data to its Transmission Planner (TP) and Planning Coordinator (PC) on an annual cycle. The PC and TP then use this information to develop system models for use in current year and future year planning studies. As such, the TP and PC would have the most accurate composite short circuit model of the system at a point a time. PRC-027-1 does not acknowledge the significant role that the TP and PC could positively play in the review of short circuit fault current studies that is contemplated by Part 1.2 and 1.3. To this end, the TP and PC should be added as functional entities to whom this standard applies. The TP and PC should establish the baseline short circuit case annually and perform a comparison to identify buses whose fault currents have deviated by more than a certain percentage. This would then trigger a settings and coordination review by the TOs and GOs.

This is a more proactive approach that the possibility of looking at settings once every six years as currently posited by the standards. With the changes in generation due to coal unit retirements and the influx of new gas units across the system, there is a real possibility of more variation in fault current levels. An annual identification of significant deviations in fault current levels is a more effective method to achieve the desired outcome using the TP and PC as an applicable entity in this process. This would also address in part the impact of System changes as identified in Part 1.2 of the proposed standard as well.

4. What is the basis for the choice of 15% as the threshold for reviewing settings? If settings were perpetually off by 14.8%, what is the impact on intended Protection System operation? Is the risk imparted to the BES of this setting inaccuracy consistent for all Protection Systems and at all voltage levels? Is there a technical basis for this choice that contemplates risk to the BES?

5. For Part 1.3, PRC-027 intended to provide flexibility to cover the various relay applications an entity might have. However, similar to what was done in PRC-023, the team should be able to identify a non-exhaustive list of known relay applications that should be included in the review versus those that would not be.

6. The term "quality review" is ambiguous and should be replaced with a more precise description of the requirement. Suggest that the language be changed to:

"Perform an additional manual or automated technical review of the settings prior to implementation. If done manually, the individual(s) performing the additional review should not have been involved in the determination of the initial settings."

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer: No

Answer Comment:

Comments: The requirements assume protective elements are primarily impacted by changes in fault current. For utilities, particularly in the west, that use impedance-based protection, the language in the standard may be deficient to cover parts of the protection system are not impacted by changes in Fault current. As such, the drafting team should consider how to address entities with schemes that are indifferent to fault current changes (i.e. line differential and impedance-based step distance). Perhaps these entities should be provided an exemption that only requires review when the zone is directly impacted. If these are not exempted, the Drafting Team should consider whether there is a technical basis for requiring a 6-year review on elements that are not impacted by changes in fault current conditions.

Review of distance settings and differential settings is not necessary until changes in the system require it. Current-only items, such as instantaneous over-currents, are the only items that need oversight related to changes that influence the fault study.

Document Name:

Likes: 0

Dislikes: 0

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

These general comments are based on two interpretations of Requirement R1:

1. Assuming that the intent is that the 'Process' identified in R1 applies to all new or changes to existing Protection System setting, we observe the following:

a. The inclusion of R1.2 tends to indicate that only those Protection System settings affected by System changes are covered.

b. The inclusion of the footnote in R1.3 tends to indicate that only 'entity designated' Protection Systems are included. The footnote also states 'entities will indicate' which makes this a requirement. This should be as a requirement not in a footnote. We question the advisability of having it buried in a footnote when an auditor will be expected to ask for it.

As such, if the intent is that entities shall follow their process for 'all new or changes to existing Protection Systems settings', then this language should be included in the main part of R1. If this is the intent, our opinion is the R1.2 and the footnote can be removed from the standard.

The following are specific:

	R1: add ‘all new or changes to existing’ R1.1: Agree R1.2: Disagree: we believe this requirement is duplicative to the intent of ‘all new or changes to existing’ R1.3: Agree, however, we believe the ‘entity designated’ defeats the concept of ‘all new or changes to existing’ and if it remains, it creates a reliability gap. R1.4: Agree R1.5: Agree 2. Assuming that the intent is that the ‘Process’ identified in R1 applies only to those protection systems identified in R1.2 and/or the ‘entity designated’ Protection Systems identified in the footnote, then these ‘applicable’ Protection Systems should be included in the Applicability of the Standard and R1.2 and the footnote should be removed from the standard. If this is the intent, we feel that the SDT has created a ‘reliability gap’ in that all new or changes to existing Protection Systems are not required to follow the other sub-requirements, such as reviewing the model and having a quality control check. Additionally it does not require entities to review settings on such things as current differential line protection, bus diff, bank diff, etc. schemes, thus allowing legacy incorrect settings to go undetected.
Document Name:	
Likes:	0
Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

BPA requests that the SDT provide guidance or solutions available to meet R1.1.4, e.g., automated checking programs for the quality review.

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Requirement R1 should be revised to read "…establish a process or processes" instead of "a process." An Entity may choose to implement a separate process for each Part.

Part 1.1. "A method to review and update the information required to develop new or revised Protection System settings." requires entities to develop a process that includes a method to review information used in two studies: Short Circuit Study and Protective Device Coordination Study. Part 1.1 only addresses the 'what' but does not address the 'when'. The 'when' for the review of the information used in the Protective Device Coordination Study is addressed in Parts 1.2 and 1.3. The 'when' for the review of information used in the Short Circuit Study is never addressed. The only evidence that is required for this standard with respect to the review of information used for the Short Circuit Study will be documentation of the 'what'; no evidence is required of 'when' it was followed. Also, Part 1.1 is not results-based; it is overly prescriptive and an inherent and necessary element for developing new or revised Protection System settings. We suggest it be removed as it does not add any value to Requirement R1. If the drafting team decides that Part 1.1 is necessary, then additional clarification is recommended regarding the scope of information to be reviewed and to what extent the review needs to be performed. Alternative wording could also be considered such as, "A procedure to track changes to the primary system and associated information required to develop new or revised Protection System settings."

It was mentioned in the April 27, 2015 Webinar that System changes will reset the baseline for Fault current studies. If that is the case, then it should be made clear in the standard. Proving system changes will be onerous. In the Rationale Box for Requirement R1, the section referring to Part 1.2 is open ended and may leave the impression that every change, even minor ones, will be considered a System change. The standard should better define "System changes."

Part 1.3. The last part of the description for "Periodic Fault current studies" is confusing. Suggest the wording be changed to the following: "… at the bus under study, and this Fault Current analysis evaluated in a time interval not to exceed six calendar years, or"

In the Rationale for Requirement R1, under Part 1.3, in the second paragraph there is the sentence "To minimize this risk, the drafting team chose a maximum Fault current deviation of 15 percent." Yet in Part 1.3 itself it says "A 15 percent or greater deviation in Fault current…" Suggest adding or removing the words "or greater" to reflect the intent. The Rationale and Part should be consistent.

Regarding the first bullet of Part 1.3, if the entity identifies a Fault current change equal to or greater than 15 percent, the periodic review should apply only to those buses identified as having a 15 percent or greater deviation in Fault current in the study and the connected buses one station away from those buses. Footnote 1 can be revised to:

Based on the Protection System design and/or susceptibility to changes in Fault current, applicable entities (Transmission Owners, Generator Owners, and Distribution Providers) will designate what Protection Systems must be included in the review(s) to ensure these Protection Systems continue to operate in the intended sequence during Faults. For buses where the Fault current changed by 15 percent or greater the Protection Systems will be those applied at the bus with the change in Fault current, and connected stations one bus away.

Part 1.4 is unclear. It is unclear as to what constitutes a "quality review", and how is it measured. It is not necessary to perform any QR. If the intent is to have this included in the process document to ensure new or revised protection system settings are properly coordinated, then this part should be revised to say, e.g.:

1.4 A check list to verify that the development of the new or revised protection system settings is coordinated among affected entities and that the proposed settings can achieve the intent of fault clearing prior to implementation.

In sub-Part 1.5.1 suggest changing "other functional entities" to "impacted (or affected) functional entities".

Requirement R2 requires the Entity to implement the R1 process. The plainest reading of the requirement only requires the process to be implemented. Suggest that R1 and R2 be combined and formatted into the CIP table format. R1 becomes “establish and implement a process or processes” and then in a table format list each part and in the adjoining column the measures to demonstrate compliance.

With regard to the discussion on sub-Part 1.3.1 at the Webinar on April 27, 2015, it was stated that once the standard is adopted utilities have 12 months to establish their fault current baseline if using the Periodic Fault Current Study method, or 6 years to perform their next Periodic review of Protection System settings if using that method of compliance. Those time frames should be spelled out in the document, especially the 12 months because it does not appear anywhere. Perhaps the best place for this is in the Implementation Plan.

The existing requirement R3 in PRC-001-1.1 calls for coordination between Generator Operators and Transmission Operators with the Host Balancing Authority:

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring T Transmission Operators and Balancing Authorities.

While the language regarding coordination by the Host Balancing Authority is not concise, the Host Balancing Authority should be made aware of relaying changes. PRC-027-1 sub-Parts 1.5.1 and 1.5.2 should be revised as follows:

1.5.1. Communicate the proposed Protection System settings with the other functional entities and the Host Balancing Authority.

1.5.2. Review proposed Protection System settings provided by other functional entities and the Host Balancing Authority, and respond regarding the proposed settings. The response should identify any coordination issue(s) or affirm that no coordination issue(s) were identified.

Document Name:

Likes: 1 Hydro-Qu?bec TransEnergie, 1, Phan Si Truc

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

FMPA has previously commented that the speed at which faults are cleared is very important to reliability, and recommends the SDT consider adding a part that requires review of Protection System settings with regard to critical clearing time.

Regarding Part 1.3, either require the use of periodic Fault current studies for specified types of Protection Systems, or leave the option out. FMPA understands the importance of considering changes in Fault current when coordinating Protection Systems, but does not see the reliability benefit of providing options in Part 1.3. From a compliance perspective, it is simpler to demonstrate compliance by always choosing the time-based methodology. As presently worded, the Fault current-based option does not add any benefit for either reliability or compliance since it is not required to be used and defaults to a six year review of settings. Also, it is not clear what conditions necessitate the establishment of a new baseline. Some language from the Option 1 discussion in the supporting material describing how the baseline is determined should be incorporated into the Requirement language.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

TVA appreciates the efforts of the Project 2007-06 SDT in developing Draft 5 of PRC-027-1. While TVA agrees with R1 and its associated sub-parts, the following comments are offered as possible improvements:

1) In R1, Part 1.2, replace "…affected by System changes" with "…affected by **Bulk Electric System** changes" because the NERC Glossary definition of "System" includes 'distribution components'.

2) R1, Part 1.3, Footnote 1 - The SDT explained that footnotes are enforceable in the 4/27/2015 project webinar, and that entities will have to justify their PRC-027 designation criteria. We recommend the SDT consider eliminating Footnote 1, and adopt an "Attachment A" approach similar to the PRC-023 standard. Doing so would tend to bring the industry to a more common understanding of the types of Protection System devices that are intended to detect Faults and initiate an isolating action, and reduce the opportunity for "gaming" the standard.

3) We agree with the SDT 4/27/2015 Webinar statement that PRC-027 "draws a line in the sand and goes forward from there." The presumption should be that existing Protection System settings have already been coordinated. We suggest adding a statement in the R1 Rationale block that memorializes the validity of existing Protection System settings as a baseline. We recommend including this statement in the R1, Part 1.3, Periodic Fault current studies rationale -

"Protection System settings existing when the Fault Current baseline is established are accepted as being coordinated consistent with the Purpose of this standard. This acknowledges that the vast majority of entities have a long history and much experience coordinating their Protection Systems."

4) In companies where a single protective relaying group performs coordination work for separate functional entities within the company, the R1, part 1.5.1 communication is often captured in the protection setting notes themselves. Please add "The drafting team also recognizes there are situations where the same protective relaying group performs coordination work for separate functional entities within the same company, and in such cases the R1, Part 1.5.1 communication is handled via internal written documentation." We suggest adding this statement in the Supplemental Material on page 15 just above Requirement R2.

Document Name:

Likes: 0

Dislikes: 0

Leo Staples - OGE Energy - Oklahoma Gas and Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE recommends including language in R1.5.1 for entities to communicate changes or settings before they are implemented. Texas RE suggests that six years is too long of a time period between a studies of Fault currents.

In general the requirements are sound but it seems the rationale behind the timing may be inconsistent with other standards such as TPL-001-4 (an annual short circuit analysis with caveats). In essence, an entity cannot tell if there is a 15% or greater deviation in Fault current without doing a study and 6 years appears to be an inordinate amount of time to lapse. Also, the “entity designated” language allows for entities to not conduct reviews if no “settings” are “designated” which defeats the reliability aspects of this standard. Footnote 1 indicates “Protection Systems” will be included but the text of 1.3 indicates which “Protection System settings”. Is the intent to designate a particular setting which then, by default, designates the Protection System where the setting is applicable? It would be beneficial to clarify the footnote.

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: No

Answer Comment:

Reclamation believes that the draft PRC-027-1 is a major improvement over the existing ambiguous language in PRC-001-1.1 regarding relay settings coordination.

Reclamation recommends updating R1.2 to reference “Protection System changes” rather than “System changes” for consistency.

Reclamation suggests that the “Supplemental Material” for Part 1.3 be updated to state that “non-fault clearing protection other than covered under PRC-019 which do not operate for faults, but are in place to protect equipment, does not require coordination between functional entities. Examples of such protection include differential relays, volts per hertz, loss-of-field, negative sequence current, stator ground, overvoltage, under frequency and out-of-step relays designed to protect generators rather than to operate for faults on the transmission system.”

Reclamation also suggests that R1.5 and its subrequirements be updated to refer to “Facilities owned by separate registered entities,” so it is clear that R1.5 refers to settings coordination between separately owned facilities. Reclamation believes that the quality review of settings required under R1.4 will assure appropriate coordination of settings for Protection Systems at adjacent facilities owned by one registered entity acting as GO and TO. Reclamation suggests that the drafting team add a footnote to R1.5 to clarify that coordination of relay settings owned by one registered entity operating as two functional entities (e.g., GO and TO) are covered by the quality review process in R1.4. Reclamation also suggests that the “Supplemental Material” section for Part 1.4 be updated to address this issue.

Finally, Reclamation recommends that the “Supplemental Material” section be renamed the “Guidelines and Technical Basis” section because this appears to be the intent of the section and for consistency with other standards.

Document Name: Reclamation PRC-027-1_Comments_05142015.docx

Likes: 0

Dislikes: 0

Michael Brown - Santee Cooper - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: No

Answer Comment:

1) In addition to our own comments, Ameren adopts the SERC PCS comments by reference. (Note: SERC Reliability Corp may actually be the submitting entity for the SERC Protection and Control Subcommittee comments.)

2) While Ameren agrees that PRC-027 is needed (we have voted in favor of previous drafts), the following items must be clarified before Ameren can support its new form: See SERC PCS Question 1 comments 1, 2, 3, and 4; SERC Question 2 comment 1; and SERC Question 4 comments 3 and 4; and Ameren specific comment 3 below.

3) We believe that the intent for R1 part 1.2 is for the entity to review Protection System settings *directly and/or significantly* affected by the changes in Part 1.1, and that Part 1.3 will capture the incremental (or less significant) changes that accumulate over time. If so, we feel this is unclear and recommend moving the similar examples from the Part 1.2 rationale to the Part 1.1 rationale and revising Part 1.2 and its rationale as follows:

a) Part 1.2: "A review of Protection System settings directly and/or significantly affected by changes identified in Part 1.1."

b) Part 1.2 Rationale: "Reviewing the affected Protection System settings when significant changes to the information identified in Part 1.1 occur maintains coordination. For example if a new BES Element (transmission line or generator) is added, Protection System settings directly protecting that new Element must be developed. And Protection System settings on BES Elements adjacent to the new Element may well be significantly affected and therefore should be reviewed as well. On the other hand, a very small change to one Element's impedance may not by itself cause a significant enough change to trigger this Part 1.2 review; the accumulation of such minor changes will be captured via Part 1.3 of the process."

Document Name:

Likes: 0

Dislikes: 0

Lewis Pierce - Santee Cooper - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

James Poston - Santee Cooper - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We question the reliability value of creating an administrative requirement that will undoubtedly be rated as a high risk based on the latest risk elements documentation. Utilities have always installed and coordinated Protection Systems to protect the safety of the general public, to protect equipment from damage, to improve reliability, and to provide good customer service. If they did not do this, they would not stay in business very long and would be subject to countless sanctions and fines from regulatory agencies. Utilities already have Protection System coordination processes in place whether formally documented or simply followed by the professional engineering staff. Furthermore, professional engineering and IEEE standards already require the coordination of protection systems, which supports that the proposed Requirement R1 is not needed.

We simply do not see how adding this standard further enhances reliability. There is no evidence that there is a widespread lack of Protection System coordination. As a result, the proposed standard could actually decrease reliability by detracting from the reliability mission to focus on paperwork. There does not appear to be any explanation to how this standard will improve reliability over what industry is already doing. If Protection System engineers are further distracted from their reliability mission by additional needless paperwork, we fear that reliability will suffer.

More specifically, we are concerned that Part 1.4 could be burdensome for small entities that may only have one Protection System engineer. How can such a small entity implement a quality review process that involves peer reviews? This could be quite costly to these entities, as they would be forced to hire consultants to conduct a peer review, which may only result in minimal reliability benefits.

We question why a Distribution Provider should be required to have a process for developing Protection Systems settings. Distribution Providers that have Protection Systems installed for detecting faults on the BES will only do so at the direction of the TO and this should be covered in the Facility connection requirements in the FAC standards. We suggest removing Distribution Provider.

The supplemental material needs to be clarified to state that the applicable entity has complete flexibility to use any combination based on any criteria not just limited to voltage or Protection System applications. The supplemental material appears to limit how both options in Part 1.3 can be combined in the standard. For instance, can an entity use one option for one bus and the other option for a different bus? Can they base it on zones of protection?

How Part 1.2 is different from Part 1.3 should be further clarified. Part 1.2 focuses on reviewing necessary Protection Systems settings based on System changes. The supplemental materials focus largely on system impedance changes. Since these would contribute to changes in fault currents, would Part 1.3 trigger the need to review these? Could Part 1.2 be combined with Part 1.3?

The drafting team should consider extending the periodic review in Part 1.3 beyond six years. The supplemental material indicates this period was selected to match the maintenance cycle for PRC-005 for relays. However, some relays (i.e. monitored) have longer maintenance cycles.

We recommend removing R1 from the standard, as a formal policy is not needed for coordination of Protection Systems. However, if the drafting team determines that the requirement must remain, we ask the team to revise the requirements to streamline the process, remove as much administrative paperwork as possible, and revise the sub-parts for clarity.

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

AECI appreciates the flexibility afforded to industry with the process document based language of draft PRC-027-1. We agree that all elements in parts 1.1 through 1.5 are essential elements of a successfull coordination process with one small disagreement in part 1.2 that could be mitigated with two insertions of "significant" and "BES". Suggested langugage: "A review of Protection System settings affected by significant BES changes." First, the insertion of the word significant would more closely align with the SDT intent and rationale given. Second usage of BES would clearly indicate the scope of the standard, which is to coordinate protection system settings that are applicable to the BES.

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The phrase “System changes” as used in R1.2 is not a defined term and is only described by a set of examples in the Supplemental Material. While this arrangement may be sufficient for compliance audits, there remains a potential gap. There may be “System changes” that warrant a review of the protection system settings that are not included in the specific set of examples provided and could lead to an entity experiencing a change that does not trigger a review of protection system settings. We suggest the Supplemental Materials include the phrase “including, but not limited to” when providing a set of example “System changes”.

The use of the undefined phrase “quality review” in R1.4 and then seemingly defining that term in the Supplemental Material could lead to issues in interpretation of what is an “adequate” quality review. The SDT should review the guidance and rationale regarding what constitutes a quality review to ensure as much potential for mis-interpretation is minimized. We would suggest the removal of R1.4.

Document Name:

Likes: 0

Dislikes: 0

Shannon Fair - Colorado Springs Utilities - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

2. Do you agree with the proposed Measures? If not, please provide the basis for your disagreement and your proposed revisions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Lynda Kupfer - Puget Sound Energy, Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Malloy - Idaho Falls Power - 3 - WECC

Selected Answer: No

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Stephenson - Great River Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer: No

Answer Comment:

We do not agree with Measure M1 as we do not agree with Parts 1.1 and 1.4.

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jim Nail - City of Independence, Power and Light Department - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alshare Hughes - Luminant - Luminant Generation Company LLC - 4,5,6 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Terrill - Luminant - Luminant Generation Company LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - PPL NERC Registered Affiliates - 1,3,5,6 - MRO,WECC,NPCC,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

See comments above.

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 1 Oxy - Occidental Chemical, 7, Greaff Venona

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer: No

Answer Comment:

Tacoma Power defers comments on the proposed measures until the industry comes to more agreement on the requirements.

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Venona Greaff - Oxy - Occidental Chemical - 7 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Please note that the CEA can ask for any evidence and the applicably entity can provide any evidence to assure compliance. Measures should support the Requirement. We have no issues with the Measures provided.

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The Measures should be updated to reflect the changes made in the Requirements based on our responses to Question 1.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment:

Modify M1 to align with the deletion of R1.1 through R1.4. M2 OK.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: No

Answer Comment:

M1 and M2 should clearly state what acceptable evidence is. The phrase "but is not limited to" can be interpreted to mean that more evidence may be required than stated.

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer: No

Answer Comment: see comments in question #4.

Document Name:

Likes: 1 Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4, James McFall, Modest

Dislikes: 0

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4
James McFall, Modesto Irrigation District, 3, 6, 4

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - Public Service Enterprise Group - 1,3,5,6 - NPCC,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Regarding M2, what constitutes “implementation” may vary, depending upon the process developed in R1. See our comments in #3 below.

Document Name:

Likes: 0

Dislikes: 0

Russ Schneider - Flathead Electric Cooperative - 4 -

Selected Answer: Yes

Answer Comment:

I don't necessarily agree with the overall expansion of scope in this standard beyond interconnected elements, but the measures are appropriate if the scope is approved.

Document Name:

Likes: 0

Dislikes: 0

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1 -

Selected Answer: No

Answer Comment:

Regarding M2, what constitutes “implementation” may vary, depending upon the process developed in R1. See our comments in #3 below.

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: No

Answer Comment:

There is a concern with M1 such that in order to demonstrate the required process is implemented that dated records must be provided. If the auditor can select any BES element internal to our system for review then we must show that it meets the latest process. This means we must have all internal locations updated such that they are ready for audit to the latest required process at the effective date since there is no implementation time line provided for R1. It seems R1 should also provide an initial time window in the implementation plan for the process to be created and implemented over time. For example, this time window could be 7-10 years since there may be many more internal lines (depending on voltages) and generation for a utility in comparison to say interconnecting 200kV lines with other utilities.

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer: No

Answer Comment:

We do not agree with Measure M1 as we do not agree with Parts 1.1 and 1.4.

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: No

Answer Comment:

The requirements do not address the extent of system conditions that the intended tripping must be reviewed (Relay failure, battery failure, etc) and is therefore open to wide interpretation. During the recent webinar, it was stated the standard is only for primary protection not backup protection yet the language in the standard does not reflect this scope.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - Richard Hoag On Behalf of: Cindy Stewart, FirstEnergy - FirstEnergy Corporation, 1, 3

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The GO is not in a position to identify this process for the BES.

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer: No

Answer Comment:

GTC is in support of the SERC Comments:

1) Revise M2 so entities that choose the

Periodic Fault current studies bullet as their trigger for a review of existing Protection System settings are aware that they will need appropriate documentation. Please add 'If the entity uses the *Periodic Fault current studies* method, acceptable evidence may include, but is not limited to, a list of each BES bus, its baseline Fault current, date of the baseline, its periodically reviewed Fault current, and the date of the review.' (Perhaps this instead belongs in the RSAW.)

Document Name:

Likes: 0

Dislikes: 0

David Thorne - PHI - Potomac Electric Power Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

CSU agrees with SMUD's Comments concerning a potentially more effective approach to PRC-027..

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Morgan - Colorado Springs Utilities - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

manon paquet - manon paquet On Behalf of: Roger Dufresne, Hydro-Qu?bec Production, 1, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Revise M2 so entities that choose the *Periodic Fault current studies* bullet as their trigger for a review of existing Protection System settings are aware that they will need appropriate documentation. Please add 'If the entity uses the *Periodic Fault current studies* method, acceptable evidence may include, but is not limited to, a list of each BES bus, its baseline Fault current, date of the baseline, its periodically reviewed Fault current, and the date of the review.' (Perhaps this instead belongs in the RSAW.)

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 3, Poston James

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

1) Revise M2 so entities that choose the *Periodic Fault current studies* bullet as their trigger for a review of existing Protection System settings are aware that they will need appropriate documentation. Please add 'If the entity uses the *Periodic Fault current studies* method, acceptable evidence may include, but is not limited to, a list of each BES bus, its baseline Fault current, date of the baseline, its periodically reviewed Fault current, and the date of the review.' (Perhaps this instead belongs in the RSAW.)

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 3, Poston James

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We do not agree with Measure M1 as we do not agree with Parts 1.1 and 1.4.

Note - These SRC comments represent a consensus of the ISOs/RTOs with the exception of ERCOT.

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3 -

Selected Answer: No

Answer Comment:

We would like to see more clarity around the measure for requirement R1. Requirement R1 has five subparts but measure M1 doesn't appear to adequately address each of these subparts (R1.1-R1.5). As is, measure M1's ambiguity leaves us unsure as to what evidence is required to adequately show compliance with requirement R1.

Document Name:

Likes: 2 OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
OGE Energy - Oklahoma Gas and Electric Co., 5, Staples Leo

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Bee - Exelon - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Vince Catania - Exelon - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dave Carlson - Exelon - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer: No

Answer Comment:

The measure for R1 and its subparts does not adequately address the expectations contained in the requirement. THere is no requirement to have a documented process per R1 but this certainly is the most forthright manner to achieve the reuqirement. Else, an entity will have to demonstrate for each setting how each subpart is demonstrated. Since R2 is the implementation piece, evidence of implementation is expected there. Absent a documented process document or perhaps a workflow to satsify R1, it is not clear how the evidence for R2 would be different from R1. It is also not clear without a process document or workflow how an entity would demonstrate that each process part was consistently addressed. In this regard and as offered in the comments, R1 and R2 could be combined into one requirement that speaks to "implementing a documented process".

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer: No

Answer Comment:

Comments: The measures should be revised to speak directly to elements being impacted..

Document Name:

Likes: 0

Dislikes: 0

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

1. In discussions with various groups the measure for M1 appears to be confusion to some folks. The addition of dated records tends to lead them down the path, of implementing the plan. Perhaps a change to clearly state that what is expected is a dated policy that indicates the entity has established ….

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We do not agree with Measure M1. Refer to our comments above regarding Parts 1.1 and 1.4.

M2 requires evidence that the process was implemented. To be specific this measure is not requiring the entity to retain evidence that each step of the process was implemented or that for each relay setting a package of information showing the protection system analysis, study files, communications with other Entities was executed. In comparison, PRC-005 requires an entity to maintain and retain evidence of the maintenance of protection systems; not to implement a maintenance program.

Document Name:

Likes: 1 Hydro-Qu?bec TransEnergie, 1, Phan Si Truc

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The Measures should indicate acceptable examples of evidence of compliance.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

While TVA generally agrees with the proposed measures, the following comments are offered as possible improvements:

Since Requirement R1 emphasizes a periodic review of Protection System settings, we suggest the wording for Measure M1 be revised slightly to read "…a process to develop **and periodically review** settings…".

We suggest revising M2 so entities that choose the "Periodic Fault current studies" method as their trigger for a review of existing Protection System settings are aware that they will need appropriate documentation. Please add "If the entity uses the Periodic Fault current studies method, acceptable evidence may include, but is not limited to, a list of each BES bus, its baseline Fault current, date of the baseline, its periodically reviewed Fault current, and the date of the review." (If adopted, this would also need to be reflected in the RSAW.)

Document Name:

Likes: 0

Dislikes: 0

Leo Staples - OGE Energy - Oklahoma Gas and Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: No

Answer Comment:

Reclamation disagrees with the proposed measures because they do not adequately describe evidence of quality reviews required under R1.4 or evidence of coordination by separate functional entities required under R1.5.

Document Name:

Likes: 0

Dislikes: 0

Michael Brown - Santee Cooper - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: No

Answer Comment:

See SERC PCS comments.

Document Name:

Likes: 0

Dislikes: 0

Lewis Pierce - Santee Cooper - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

James Poston - Santee Cooper - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The measures do not provide guidance regarding how compliance will be measured by a Compliance Enforcement Authority. The measures are so generic that a single measure could be written for both requirements and could be summed up as “evidence that demonstrates compliance with the requirement.” According to the Standards Process Manual, a measure “provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement.” The measures in the current draft do not identify any specific evidence or types of evidence.

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Fair - Colorado Springs Utilities - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

3. Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer: No

Answer Comment:

Please clarify when the process has to be implemented for the first time. It is not entirely clear. Maybe it is 6 years???? Also suggest a two year implementation period instead of one due to the complexity.

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lynda Kupfer - Puget Sound Energy, Inc. - 5 -

Selected Answer: No

Answer Comment:

There seems to be conflict with timelines, comparing the Standard itself to the Implementation Plan. R2.2 places a timeline for completion of 90 calendar days after the completion of the R1 assessment, and word has filtered down that WECC said that if the R1 assessment is completed prior to the effective date, the clock starts ticking on the R2.2 90 days. However, the implementation plan says that R2.2 has to be completed with 90 calendar days of the effective date of the Standard. That could be a very different end date for R2.2.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Malloy - Idaho Falls Power - 3 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Stephenson - Great River Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer: No

Answer Comment:

The Implementation Plan should be extended to 24 months. As it stands now, entities only have 12 months to develop a process, establish Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review.

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jim Nail - City of Independence, Power and Light Department - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alshare Hughes - Luminant - Luminant Generation Company LLC - 4,5,6 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Terrill - Luminant - Luminant Generation Company LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

AEP does not believe that 12 months is adequate for the Implementation Plan, and recommends that it be increased to 24 months, which we believe is more reasonable.

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - PPL NERC Registered Affiliates - 1,3,5,6 - MRO,WECC,NPCC,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

See comments above.

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5 -

Selected Answer: No

Answer Comment:

ICLP can only commit to providing an initial baseline of our Fault relay performance within a year of FERC's approval if the scope is limited to our GO-TO interconnections. Otherwise, entities will need much more time to verify that every one of their relay systems react in the proper sequence in response to a Faults.

Document Name:

Likes: 1 Oxy - Occidental Chemical, 7, Greaff Venona

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer: No

Answer Comment:

Unless an entity can reasonably demonstrate that they have documentation of existing coordination studies, there needs to be an implementation period during which coordination of applicable Protection System settings are initially documented. This documentation will serve as a baseline for Parts 1.2 and 1.3 of Requirement R1.

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Venona Greaff - Oxy - Occidental Chemical - 7 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The Implementation Plan should be extended to 24 months. As it stands now, entities only have 12 months to develop a process, establish Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: No

Answer Comment:

12 months is a reasonable time to establish the process required in R1, but not sufficient time to implement the process as required in R2. A six calendar year time interval for R2 would be more reasonable and aligns with the interval stated in Part 1.3.

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer: No

Answer Comment:
IBID

Document Name:

Likes: 0

Dislikes: 0

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4
James McFall, Modesto Irrigation District, 3, 6, 4

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - Public Service Enterprise Group - 1,3,5,6 - NPCC,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

An entity must be in compliance with the requirements of a standard on day 1. The Implementation Plan allows 12 months after approval of the standard for this to occur. If a process is completed per R1 within 12 months, an entity is compliant with R1. But what constitutes compliance with “implementing the process established in accordance with requirement R1”? For example, if an entity’s process adopts the a six-year review cycle of its Protection System setting as permitted in the second bullet in Part 1.3, what would it be implementing on day 1?

The team should consider requiring an entity-specific implementation timeline to be included in the process developed in R1, with R2 stating that an entity shall implement its R1 process in accordance with its timeline in R2.

Document Name:

Likes: 0

Dislikes: 0

Russ Schneider - Flathead Electric Cooperative - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1 -

Selected Answer: No

Answer Comment:

An entity must be in compliance with the requirements of a standard on day 1. The Implementation Plan allows 12 months after approval of the standard for this to occur. If a process is completed per R1 within 12 months, an entity is compliant with R1. But what constitutes compliance with "implementing the process established in accordance with requirement R1"? For example, if an entity's process adopts the a six-year review cycle of its Protection System setting as permitted in the second bullet in Part 1.3, what would it be implementing on day 1?

The team should consider requiring an entity-specific implementation timeline to be included in the process developed in R1, with R2 stating that an entity shall implement its R1 process in accordance with its timeline in R2.

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: No

Answer Comment:

See our response to Question 2 above.

The implementation plan indicates there is 12 months to become compliant. This could create confusion since many aspects of the standard are based on a 6 year interval. Consider if the implementation plan should match the maximum interval or clearly address what must be completed to be compliant as part of the implementation plan.

Can the drafting team clarify if all protection systems on an entities' system must have a coordination evaluation meeting the new process for PRC-027 within the first six years? The standard also gives the impression that the baseline fault current percentage option does not require all protection systems to be evaluated for coordination until the fault current threshold is met.

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer: No

Answer Comment:

The Implementation Plan should be extended to 24 months. As it stands now, entities only have 12 months to develop a process, establish Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review.

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: No

Answer Comment:

24 months would be more appropriate given the amount of work necessary to meet compliance.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: No

Answer Comment:

It is not clear how long an Entity has to develop a baseline, 12 months or 6 years. We would appreciate clarification on this in the implementation plan.

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - Richard Hoag On Behalf of: Cindy Stewart, FirstEnergy - FirstEnergy Corporation, 1, 3

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Thorne - PHI - Potomac Electric Power Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

CSU agrees with SMUD's Comments concerning a potentially more effective approach to PRC-027. In addition to supporting their comments CSU also would make the following comment if the standard were to remain similar to its current construction.

Is it the intention that an entity would have an initial/baseline review of all protections system settings completed prior to the effective date of this standard? If this is the intent then the implementation period needs to be extended or a phased approach adopted as is done with PRC-005-2 for example.

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Morgan - Colorado Springs Utilities - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

manon paquet - manon paquet On Behalf of: Roger Dufresne, Hydro-Qu?bec Production, 1, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 3, Poston James
Santee Cooper, 5, Pierce Lewis

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 6, Brown Michael
Santee Cooper, 3, Poston James

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 1 OGE Energy - Oklahoma Gas and Electric Co., 5, Staples Leo

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. agrees with NPCC on the following:

The Implementation Plan should be extended to 24 months or greater. As it stands now, entities are only given 12 months to develop a process, establish a Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review. This period is far too short, and should be extended.

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Bee - Exelon - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Vince Catania - Exelon - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dave Carlson - Exelon - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

1. The implementation plan should explicitly indicate that entities are not expected to be 100% compliant with R2 on the effective date of the standard. Further, the implementation plan should state that the applicable entities are to begin implementing the process it established in response to R1 on the effective date of the standard.

2. There is an issue with the establishment of the baseline noted in our answer to question #4 which potentially could be addressed in the Implementation Plan.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The Implementation Plan needs to address the 6 year review in Part 1.3. Is this 15 percent per year for the first 6 years? Do entities need to demonstrate when the last review was done prior to effective date of the Standard?

The Implementation Plan should be extended to 24 months. As it stands now, the 12 months entities have to develop a process, establish Fault current baseline, and establish a tracking tool for Fault current baseline changes and/or periodic review is not enough time.

Document Name:

Likes: 1 Hydro-Qu?bec TransEnergie, 1, Phan Si Truc

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

We agree with the proposed Implementation Plan as it was explained by the SDT during the the 4/27/2015 project webinar. However, we believe a modified format would add clarity around the PRC-027-1 compliance dates. As written, it could be interpreted that every applicable Protection System setting that already exists needs to be reviewed using the process established in accordance with Requirement R1 by the “first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required to go into effect.” We believe that completing a review of all existing applicable settings concurrently with the effective date of R1 is unrealistic, and is not what the drafting team intended. We request the SDT consider modifying the Implementation Plan format as suggested below to help add clarity around the R2 compliance date for pre-existing PRC-027 applicable settings.

Requirement R1

"...first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority…"

(Rationale – consistent with the posted Implementation Plan)

Requirement R2 (for new Protection Systems to be placed in service after the effective date of R1, or for existing Protection System settings affected by Bulk Electric System changes occurring after the effective date of R1) :

"...first day of the first calendar quarter that is eighteen (18) months after the date that the standard is approved by an applicable governmental authority…"

(Rationale – this would give entities ~6 months to start implementing the R1 process for new settings and begin to build an evidence trail for R2)

Requirement R2 (for existing Protection System settings that were developed and implemented prior to the R1 effective date):

"...first day of the first calendar quarter that is eighty-four (84) months after the date that the standard is approved by an applicable governmental authority…"

(Rationale – this would more clearly communicate the six year interval intended by the drafting team, following development of the R1 process, to fully implement the initial six year review interval required by R1/1.3. Some legacy settings may be reviewed earlier if BES changes warrant.)

Document Name:

Likes: 0

Dislikes: 0

Leo Staples - OGE Energy - Oklahoma Gas and Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: No

Answer Comment:

Reclamation suggests that a two-year implementation period is more appropriate for updating both internal and external procedures regarding relay coordination. Particularly with regard to R1.5 external coordination procedures, registered entities may need to coordinate procedures with a number of other registered entities.

Document Name:

Likes: 0

Dislikes: 0

Michael Brown - Santee Cooper - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lewis Pierce - Santee Cooper - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

James Poston - Santee Cooper - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The implementation plan is not clear when the first performance of the tasks required in the Protection System coordination process document is required. For example, when must the first review of Protection System settings per Part 1.2 or 1.3 be conducted? On the effective date of the standard? Based on a date established in the process document?

We ask the drafting team to combine PRC-001 with PRC-027 to avoid confusion and cross referencing of two standards on the same topic. This should be handled in the development phase, which would require a modification to the implementation plan.

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

AECI believes that for some systems, especially those with a large amount of interconnections, there may be additional time past 1 year to properly establish **accurate** baselines and coordinate a process docuent with neighbors. An additional year for development of the plan and baselines is requested. Six year review periods seems reasonable and adequate.

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Fair - Colorado Springs Utilities - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

4. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lynda Kupfer - Puget Sound Energy, Inc. - 5 -

Selected Answer:

Answer Comment:

CIP-014-2 is positioned to become effective the day after CIP-014-1 becomes effective, with -1 being retired at midnight of the same day it becomes effective. This might not be an issue of -1 is superseded by -2, and never becomes effective, but you never know.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Malloy - Idaho Falls Power - 3 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Stephenson - Great River Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

(1) This Standard references the terms “BES Elements.” In reviewing the NERC Glossary, there are many references to merely “Elements” without the preceding “BES” adjective, i.e., Remedial Action Scheme definition. What is the difference between “BES Elements” and “Elements” (without the BES)? Is the term “Element” without BES reference to elements that are non-BES, and if that is the case, does subpart “e.” of the RAS definition apply to non-BES Elements as there is no preceding “BES”?

(2) In R1 Part 1.3, “current baseline” is not defined. Current baseline is defined in the Supplemental Material Section, but because the Supplemental Material Section is merely guidance, can an entity make up its own definition of “current baseline”?

(3) In R1 Part 1.3, the Requirements nor the implementation plan define when a “time interval” begins. This should be in the Requirements or implementation plan, because the supplemental material section is unenforceable.

(4) In R1 Part 1.3, if a review was performed on March 1, 2017 and an entity had 6 calendar years in which to complete the review, is that 6 full calendar years? Meaning, would an entity not have to complete another review until December 31, 2023?

(5) In R1 Part 1.5.3, this Requirement merely states that the coordination issues need to be “addressed” prior to implementation. We have two questions on this requirement, the first being that after reviewing the supplemental guidance material, that under certain circumstances, such as where additional system modifications are needed, that such modifications do not need to take place before the settings changes if the entity didn’t originally place those modifications into the scope of the settings changes project. Because the Requirement does not require the modifications to take place in any future time, can the drafting team describe in more detail how these issues are “addressed prior to implementation”?

(6) In the Supplemental Material section, there are references to the terms “BES Protection System” and “Protection System.” The Standard applies to “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted elements.” For purposes of this Standard, is a BES Protection System a Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted elements?

(7) In Requirement R1, is the 15% value 15.% with two significant figures in that if we have a deviation of 14.6% we need to perform an evaluation as it rounds up to 15% or are there more significant figures, i.e., 15.0%?

(8) In Requirement R1, if an entity uses the time based option and uses a recent short-circuit study for its baseline study, does the 6-year option 2 time frame start from the time of enforcement of the Standard or from the date the short-circuit study was finalized? The answer to this question does not appear to be in the Requirement.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment:

As indicated in a number of our previous comments, we continue to disagree with the treatment to Requirement R1 in the proposed PRC-001-3.

Requirement R1, as written, is not measurable and should be rescinded or mapped into another standard. While revising PRC-001-3 to reflect the mapping of certain requirements (e.g. R3) to PRC-027 is necessary, not

revising other requirements that are unclear or unnecessary in the same standard that being revised fails to take advantage of the opportunity of an initiated project. Quite simply, familiarity with and knowledge of the purpose and limitations of Protection System schemes applied in an operating entity's area are inherent to the entities that are required to comply with the rest of PRC-001-2. R1, therefore, is redundant and unnecessary. In addition, this requirement is not measurable. An analogy to this argument is that an RC needs to monitor its system conditions against IROLs. Since the RC is already required to prevent exceedances of IROLs and to apply mitigating measures to reduce flows to below IROLs within Tv, having monitoring capability is inherent to achieving these objectives. Hence in IRO-009-1, there are no requirements that stipulate the need to monitor flows/conditions against IROLs.

The above view is consistent with the Independent Experts Review Panel's recommendation. If the SDT continues to opine that the retirement of PRC-001-2 Requirement R1 falls outside the scope of this project, then we would suggest the SDT to immediately submit an addendum or revised SAR to the Standards Committee for approval to post for industry comment, then revise/remove R1 accordingly.

We offered a similar comment about a year ago when the proposal was to keep only R1 in PRC-001 until this requirement is incorporated into a PER standard. No actions have been taken since. Had an addendum SAR or a revised SAR been posted then, the PRC-001-2 R1 issue would have been fully addressed by now. We are disappointed that over this period, neither NERC staff nor the PRC-027 SDT took the proactive action to proactively address/close out the issue. Today, we still have a requirement that is improper and not measurable. Once again, we urge NERC staff and the SDT to act now to post an addendum SAR or a revised SAR to fully resolve this issue. Further delay in addressing the issue until a new project is initiated may result in dragging the approval of PRC-027-1 for another several months to a year.

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

We would like this standard to state which relay elements that NERC wants to see coordinated. This could be in an attachment similar to PRC-019-1 and 025-1. Specifically for generator protection, there are so many different protection elements used that it would make the standard easier to use for the end user and an auditor if they had a specific set of relay elements to look for.

Finally, we would like to see an exception for distributed resources similar to what project 2014-01 is working on for other standards. Typically distributed resources do not look out to the transmission system, but unless they are excluded this will need to be examined and documented.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

It makes sense that, out of the five components of the NERC-defined Protection System, the owner of the Protective relays which respond to electrical quantities would be the one required to meet PRC-027. To address situations where multiple TOs or GOs may own different portions of the Protection System, LCRA TSC recommends changing to the language in the Applicability section to read as shown below:

4.1.1 Transmission Owner (that owns the Protective relays which respond to electrical quantities portion of the Protection System)

4.1.2 Generator Owner (that owns the Protective relays which respond to electrical quantities portion of the Protection System)

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer:

Answer Comment:

Comments: R1.3 needs clarity around establishing the initial fault current baseline. Does this occur prior to Effective Date? Any time prior to first 6 year fault current review?

R1.5.3 needs clarity which party is responsible to verify issues are addressed prior to implementation. We assume the SDT intends this responsibility to be only on the party proposing the settings.

Document Name:

Likes: 0

Dislikes: 0

Jim Nail - City of Independence, Power and Light Department - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alshare Hughes - Luminant - Luminant Generation Company LLC - 4,5,6 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Terrill - Luminant - Luminant Generation Company LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

The applicability of PRC-027 should be limited to Protection Systems installed on interconnecting elements. There is no justification to include all BES Protection Systems in the standard. The requirements in PRC-001-2, R2 and R3, which PRC-027 is replacing, are limited to the coordination of protection systems between different entities. The SAR posted for PRC-001-1 System Protection Coordination (Project 2007-06) does not include expanding the scope of the standard to include all BES protection systems. If FERC seeks a protection system coordination standard that includes all BES protection systems, then the NERC standard development process should be followed by creating a new SAR.

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - PPL NERC Registered Affiliates - 1,3,5,6 - MRO,WECC,NPCC,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6

Selected Answer:

Answer Comment:

GRE supports the comments of the MRO NSRF and ACES

Document Name:

Likes: 0

Dislikes: 0

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5 -

Selected Answer:

Answer Comment:

It took four iterations of PRC-027-1 to come up with requirements acceptable to stakeholders that captured each relay owner's responsibility during the course of a coordinated assessment. This included the types of system changes that would trigger a coordinated study, the information to be shared, the timeframes to respond, and the expected actions to take at each point of the process. Although FERC staff did not call for the removal of those requirements, the project team has chosen to do so. These requirements should be reinstated. Without them, it is possible than an unresponsive neighbor cannot be compelled to participate in a coordinated relay assessment – leaving entities exposed to a NERC violation.

Document Name:

Likes: 1 Oxy - Occidental Chemical, 7, Greaff Venona

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

While we agree that Part 1.3 is an essential element of a successful coordination process, we have concerns about how the baseline bus fault currents are determined in the "Supplemental Material" Section addressing Part 1.3. The last paragraph on page 13 of the standard states that “The baseline can be Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect.” That implies that an entity must search its archives to determine whether it has available documentation of Fault currents that were used for initial settings. Then, only if no documentation can be found, the entity can choose to use its most recent short-circuit study data for the baseline. Tri-State believes that, if the second option is acceptable for cases when no documentation is available, it ought to be acceptable to use the most recent short-circuit study at the time the standard becomes effective for all of its bus Fault currents. Our recommendation is to remove “where not available” and the associated commas from the referenced paragraph on page 13.

Document Name:

Likes: 1 Tacoma Public Utilities (Tacoma, WA), 1, Merrell John

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment:

Tacoma Power thanks the drafting team for their efforts and appreciates the opportunity to comment and help to guide the development of this standard.

Together with several other entities, Tacoma Power questions the need to mandate intra-entity coordination as part of an enforceable standard. Despite its reservations about the scope of the proposed standard, Tacoma Power assumes that, because FERC staff expressed concern that intra-entity coordination be included, there is little that the industry can do to limit the scope of PRC-027-1 to inter-entity coordination (i.e., Part 1.5 of Requirement R1). Tacoma Power's comments are based upon this assumption.

On page 14 of the Supplemental Material section, Tacoma Power recommends changing 'necessitates' to 'allows.' An entity may elect to review settings prematurely and reset the baseline for that/those bus(es), even though changing the baseline is not necessary.

The draft standard does not seem to address what latitude applicable entities will have when defining their tolerance for coordination. For example, under how many System contingencies does coordination need to be maintained? Must coordination be maintained for all single Protection System component failures? On the other hand, provided that planning and operations personnel/entities are aware, could applicable entities intentionally mis-coordinate Protection Systems? Tacoma Power's understanding is that the drafting team primarily has the following intents. (1) An applicable entity should be aware of how their Protection Systems will likely perform during Fault conditions under identified contingencies. (2) An applicable entity should be aware of contingencies under which Protection System performance during Faults may be unknown or adverse. (3) Operations and planning personnel/entities should be aware of contingencies under which Protection System performance during Faults may be unknown or adverse. To this end, Tacoma Power recommends that the Purpose be "To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those Faults, such that the Protection Systems operate in the intended sequence during Faults." Similarly, Tacoma Power recommends Facilities be "Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those

Faults." This revised verbiage replaces "those faulted Elements" with "those Faults" to allow for removal of Elements other than the faulted Element(s), provided that the sequence is intended.

The Purpose statement includes the phrase "such that the Protection Systems operate in the intended sequence during Faults." This could be interpreted in a couple ways. The first interpretation is that the primary Protection System is supposed to operate first and not the backup Protection System. The second interpretation is that, not only does the primary Protection System need to operate first, but that the backup Protection System must be capable of operating for (detect) all Faults within the primary Protection System's zone of protection. Could the drafting team please identify the more correct interpretation of the Purpose? The burden of proof could be substantially different between the two interpretations.

If PRC-027-1 is approved, Tacoma Power's understanding is that a Mis-operation due to mis-coordination will not automatically imply that a violation of PRC-027-1 occurred.

Remove the extra 'The' just before Compliance Monitoring and Enforcement Program.

Tacoma Power believes that the drafting team should leverage the Lower and Moderate VSLs. The Lower VSL for both Requirements R1 and R2 should be for failing to include one Part. The Moderate VSL should be for failing to include two Parts, the High VSL should be for failing to include three Parts, and the Severe VSL should be for failing to include four (or more) Parts OR for failing to establish/implement the process. FERC's VSL G1 only states that the VSL assignment should not have the UNINTENDED consequence of lowering the current level of compliance. Furthermore, the scope of applicability of PRC-027-1 is much greater than PRC-001-1, so it is reasonable for PRC-027-1 to leverage the Lower and Moderate VSLs, even though PRC-001-1 did not. If the drafting team disagrees, then Part 1.5 of Requirement R1 should be separated into a separate requirement so that the other Parts of Requirement R1 can have more graduated VSLs since these other Parts do not map as well to PRC-001-1.

Compared to Requirement R1, Tacoma Power is not convinced that the justification has been made for a High VRF for Requirement R2.

Tacoma Power's understanding is that, where the NERC-defined term 'Fault' is used, the standard primarily, if not exclusively, means short circuits, as opposed to broken wires or intermittent connections.

Although entities are supposed to develop their own processes, the draft standard is specific enough that a flow chart may be helpful to visualize the process.

In the Supplemental Material section, it would be very helpful to include a series of examples of how Part 1.2 might be triggered and how an applicable entity might approach the review of Protection System settings. Examples might include a new substation, a new transmission Element, a new generator, a change in the impedance of an Element, and/or Protection System setting changes without any System change (e.g., setting philosophy change, relay replacements). In the examples, it would be helpful if the drafting team could discuss how to determine how far back into the existing System to look in response to the triggers.

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer:

Answer Comment:

In the Applicability Section of PRC-027-1, the DP applicability is limited to those DPs that "own Protection Systems identified in the Facilities section 4.2." However, throughout the standard when the DP is identified as the applicable entity, the qualifier is not included. Does the SPCSDT believe that it is clear in the requirements and rationale boxes that the DP applicability is only to those DPS that own Protection Systems identified in the Facilities section 4.2? If one were to read the requirements without fully understanding the applicability section, it appears that they are applicable to all DPs. Would it be better for clarity to include the "own Protection Systems identified in the Facilities section 4.2" language with all references to the DP?

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

While we like the opennes of the standard, we would like more defined measures to document compliance. Additionally, we would like a reference document that addresses the administrative requirements that the program would have to address.

Document Name:

Likes: 0

Dislikes: 0

Venona Greaff - Oxy - Occidental Chemical - 7 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

ReliabilityFirst agrees that PRC-027-1 helps to alleviate the risk of insufficient coordination of Protection Systems installed to detect Faults on BES Elements and isolate those faulted Elements (such that the Protection Systems operate in the intended sequence during Faults). ReliabilityFirst offers the following comments related to the term "coordination" for the Standard Drafting Team's consideration:

1. **ReliabilityFirst believes that the term "coordination" as it is used in Requirement 1, Parts 1.5.2 and 1.5.3 is ambiguous and notes that it is not defined within PRC-027-1 or the NERC Glossary Terms. Adding to this ambiguity, the term is used within a number of other Standards, and could be interpreted to refer to the setting of Protection Systems *or* to communications between entities. To add clarity to PRC-027-1, ReliabilityFirst recommends replacing the term "coordination" with the term "Protection System Coordination." Listed below is ReliabilityFirst's proposed NERC Glossary definition of "Protection System Coordination" for the Standard Drafting Team's consideration:**

Protection System Coordination - The setting of Protection Systems installed for the purpose of detecting and isolating Faults on BES Elements, such that the Protection Systems operate in a defined sequence in an effort to remove such Faults from the BES.

1. **ReliabilityFirst recommends the following changes to Requirement 1, Parts 1.5.2 and 1.5.3 to incorporate this new definition of “Protection System Coordination” (highlighted in red below):**

1.5.2. Review proposed Protection System settings provided by other functional entities, and respond regarding the proposed settings. The response should identify any Protection System Coordination issue(s) or affirm that no Protection System Coordination issue(s) were identified.

1.5.3. Verify that any identified Protection System Coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation.

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

The NSRF has noticed that the SDT has written the following note in PRC-001-3 Redline with mapping: *The Independent Experts concluded that PRC -00 Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC’s Reliability Standards be consolidated*.

The NSRF questions why the SDT has not addressed this issue?

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

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Selected Answer:

Answer Comment:

We wish to express support for the direction the Standard Drafting Team has taken in this major re-write to formulate Draft 5 of the Standard. Some clarifications and extension of the Implementation Plan, as noted in the comments, are all that should suffice to arrive at a future successful draft Standard.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer:

Answer Comment:

SMUD thanks the drafting team for the opportunity to comment. SMUD would prefer more of a carrot and stick approach. SMUD views the current draft as burdensome due to the amount of documentation that will be needed to prove steps 1.1-1.4 were performed on every single BES Protection System. A better approach would be to establish a trigger or threshold that says you must follow these rules if you have “too many” coordination Misoperations. This trigger or threshold provides entities an incentive to coordinate relay settings thus avoids the compliance burden. This would be in alignment with the goal of reducing Misoperations rather than documenting procedural compliance. We think this would better represent RBS and at least we could support such an approach.

Document Name:

Likes: 1 Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4, James McFall, Modest

Dislikes: 0

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4
James McFall, Modesto Irrigation District, 3, 6, 4

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

While ATC supports the direction the SDT is going on this draft Standard, there are still some concerns that result in ATC maintaining a “negative” ballot position.

On page 13 of 16 of Draft 5, ATC recommends removing the phrase, “where not available” from the last paragraph. An entity should be able to use the fault current values from the most recent short-circuit study for a baseline. Fault current values from the initial settings, while available, could be contained in many different formats from prior years and not readily available in a database.

In re-working Draft 5 of PRC-027-1, ATC recognizes and appreciates the drafting team’s efforts to allow an entity flexibility in developing its coordination process. However, ATC also believes that the focus of PRC-027-1 should be on improving BES reliability and the current draft does not necessarily achieve that end. The definition of a review could be left up to interpretation, which could lead some companies to perform the function to meet the requirement with no benefit realized. Where PRC-004 data provides a mechanism to measure performance, the better means to achieve reliability performance would allow each entity to use its company’s Misoperations data and the greater industry data to develop a program that addresses its greatest need. There is no clear connection in the

PRC-027-1 requirements to system performance using PRC-004 Misoperations data, and as echoed in our comments to Question 1, there is no feedback loop for monitoring improvement.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - Public Service Enterprise Group - 1,3,5,6 - NPCC,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

a. Clarify the scope of PRC-027-1: We understand from the Webinar on 4/27/15 that the standard is intended to address Protection System setting for Faults associated with Normal Clearing (i.e., the Protection Systems operate properly per the definition of "Normal Clearing") and normal operation of the interrupting devices (i.e., they also operate correctly). In other words, the setting of back-up Protection Systems that would operate due to the failure of a Protection System or circuit breaker to operate correctly is outside the scope of the standard. The standard should clearly state this in the Applicability section.

b. Provide default information by separate attachments to the standard: To avoid additional work by each registered entity in developing its process under R1 process, the standard should have certain "default" information provided in separate attachments as discussed below. Furthermore, an entity should be able to either adopt the attachment or modify it, provided that its modifications are explained in its process.

· - Part 1.1: This subpart is presently "A method to review and update the information required to develop new or revised Protection System settings." We believe that "the information required to develop new or revised Protection System settings" is not entity-specific, but Protection System-specific. That information should be included in the standard via an attachment.

· - Part 1.3: This subpart should also reference an attachment to the standard that designates the Protection System types that need to be included in the periodic review. For example, It would not make sense for one entity to include some Protection System, and another entity to exclude the same protection system due to a different interpretation of the standard. There are only a finite number of protection system types, and they should be listed as “included” or “excluded” as part of the standard. That information should be included in the standard via an attachment.

c. Clarify the first bullet in Part 1.3 “Periodic Fault current studies” on two points:

· The phrase “an established Fault current baseline” is unclear with respect to timing. It would be clearer if the team replaced the aforementioned phrase with the following one: “a Fault current study that is no older than six calendar years.” Then a 2020 review for a bus under this bullet must use Fault current that was calculated in 2014 or later.

We recommend modifying the phrase “, and evaluated in a time interval not to exceed six calendar years” in the first bullet in Part 1.3 to “, with such Fault current changes evaluated in a time interval not to exceed six calendar years. “

Document Name:

Likes: 0

Dislikes: 0

Russ Schneider - Flathead Electric Cooperative - 4 -

Selected Answer:

Answer Comment:

I am compelled by other commentors that pointed out in previous drafts that the shift from inter-connected elements to intra-connected elements is potentially a broad expansion of scope for little reliability benefit. The industry just spent several years getting more definition on the scope and most other protection system issues are covered in other standards as noted in the Protection System Issues Addressed by Other Projects.

More specifically, if the intra-coordination regulatory burden does have reliability benefit it should be limited to BES Transmission Owners in the applicability section. 4.1.2, 4.1.3, and 4.2 should be eliminated.

Document Name:

Likes: 0

Dislikes: 0

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1 -

Selected Answer:

Answer Comment:

a. Clarify the scope of PRC-027-1: We understand from the Webinar on 4/27/15 that the standard is intended to address Protection System setting for Faults associated with Normal Clearing (i.e., the Protection Systems operate properly per the definition of “Normal Clearing”) and normal operation of the interrupting devices (i.e., they also operate correctly). In other words, the setting of back-up Protection Systems that would operate due to the failure of a Protection System or circuit breaker to operate correctly is outside the scope of the standard. The standard should clearly state this in the Applicability section.

b. Provide default information by separate attachments to the standard: To avoid additional work by each registered entity in developing its process under R1 process, the standard should have certain “default” information provided in separate attachments as discussed below. Furthermore, an entity should be able to either adopt the attachment or modify it, provided that its modifications are explained in its process.

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c. Clarify the first bullet in Part 1.3 “Periodic Fault current studies” on two points:

· The phrase “an established Fault current baseline” is unclear with respect to timing. It would be clearer if the team replaced the aforementioned phrase with the following one: “a Fault current study that is no older than six calendar years.” Then a 2020 review for a bus under this bullet must use Fault current that was calculated in 2014 or later.

We recommend modifying the phrase “, and evaluated in a time interval not to exceed six calendar years” in the first bullet in Part 1.3 to “, with such Fault current changes evaluated in a time interval not to exceed six calendar years. “

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

In the past for draft 4 of PRC-027 it was stated in part 1.1.1 of the application guidelines that, “Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” Considering this, why are additional standard requirements being implemented if data does not support it?

How was the 15% change in fault current determined? Perhaps this percentage should be eliminated and allow each entity to specify this type of fault current percentage threshold as part of their own process.

R1.3. states there should be a review of protection system “settings”. Should this state protection system “coordination-related settings”? This standard is not addressing all aspects of how to set a relay but is addressing coordination, which involves timers and time current curves rather than say a distance impedance reach magnitude. Consider if “settings” should be changed to “coordination related settings” in the standard.

A 6 year time horizon option to review settings seems a bit arbitrary. A longer time horizon may be better suited for very large systems. Consider allowing this time interval to be defined as part of the process for each utility so they can be flexible since the number of systems to coordinate will vary greatly between utilities.

For R1.1. why does PRC-027 contain all the detailed model and equipment verifications for an auditor while other standards like PRC-006, 010, 019, 023, 024 and 025 do not? The need for accurate model and equipment data is correct; however, the efforts to supply proof of this information to an auditor appears to be excessive in terms of auditing proof compared to other standards. The result of this requirement as it will be implemented in R2. is that the auditor will essentially be reviewing the relay settings and accuracy of the model and equipment records. This does not seem practical. We would recommend removal of this requirement.

In the purpose statement, could Protection Systems be changed to Protective Relays? Protective relays are installed for the purpose of detecting faults on BES elements and isolating those faulted elements. We do not feel that associated communications systems, voltage and current sensing devices, station batteries, or DC control circuitry are installed for those purposes.

In the Rationale for Requirement R1., we don’t consider all the listed examples of information to be essential for coordination, especially the functional drawings, which are very high level, and station configuration, which would be single bus/ring bus/etc. Why are these essential?

In the Rationale for Requirement R1, Part 1.2., there are absolute terms regarding system changes, such as “that alters ANY”, and “result in A change”. We suggest a change to some wording that would allow some minor changes that wouldn’t require a coordination review.

Regarding Requirement R1, we would need to review and verify all line, generator, and transformer impedances to verify our short circuit study is accurate. The supplemental material calls for a review of interconnected TO, GO, and DP information to determine whether their systems are correctly modeled in the short circuit study. This is a concern in that we would have to determine other utilities' models.

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment:

As indicated in a number of our previous comments, we continue to disagree with the treatment with respect to Requirement R1 in the proposed PRC-001-3.

Requirement R1, as written, is not measurable and should be rescinded or mapped into another standard (e.g. a PER standard) and revised to become a training requirement. While revising PRC-001-3 to reflect the mapping of certain requirements (e.g. R3) to PRC-027 is necessary, not revising other requirements that are unclear or unnecessary in the same standard that is being revised fails to take advantage of the opportunity of an initiated project. Quite simply, familiarity with and knowledge of the purpose and limitations of Protection System schemes applied in an operating entity's area are inherent to the entities that are required to comply with the rest of PRC-001-2. R1, therefore, is redundant and unnecessary. An analogy to this argument is that an RC needs to monitor its system conditions against IROLs. Since the RC is already required to prevent exceedances of IROLs and to apply mitigating measures to reduce flows to below IROLs within Tv, having monitoring capability is inherent to achieving these objectives. Hence in IRO-009-1, there are no requirements that stipulate the need to monitor flows/conditions against IROLs.

The above view is consistent with the Independent Experts Review Panel's recommendation. If the SDT continues to opine that the retirement of PRC -
001 -2 Req
would suggest the SDT to immediately submit an addendum or revised SAR

to the Standards Committee for approval to post for industry comment, then revise/remove R1 accordingly.

We offered a similar comment about a year ago when the proposal was to keep only R1 in PRC-001 until this requirement is incorporated into a PER standard. No actions have been taken since. Had an addendum SAR or a revised SAR been posted then, the PRC-001-2 R1 issue would have been fully addressed by now. We are disappointed that over this period, neither NERC staff nor the PRC-027 SDT took the proactive action to proactively address orclose out the issue. Today, we still have a requirement that is improper and not measurable. Once again, we urge NERC staff and the SDT to act now to post an addendum SAR or a revised SAR to fully resolve this issue. Further delay in addressing the issue until a new project is initiated may result in dragging the approval of PRC-027-1 for another several months to a year.

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer:

Answer Comment:

Entergy is not in agreement with the selection of High Violation Severity Level (VSL) for Requirement 1.5.3. A more appropriate VSL would be Lower VSL.

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - Richard Hoag On Behalf of: Cindy Stewart, FirstEnergy - FirstEnergy Corporation, 1, 3

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

FE believes the TO should be identified as the entity to establish the system protection coordination and be responsible for PSCSs (Power System Coordination Studies), Fault Studies, Short Circuit Studies, etc., to prove coordination. Communication to the GO should also be the TO's responsibility. The GO would be responsible to implement setting changes as directed by the TO, where applicable and if able. The GO's connection to the BES normally ends/terminates with the Generator Step Up transformer so the GO does not have the data to perform any Power System Coordination Studies, Fault Studies, or Short Circuit Studies.

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer:

Answer Comment:

GTC is in support of the SERC Comments:

1) Please revise the Purpose because it implies the Protection System isolates the fault. The NERC defined Protection System includes the trip coil but stops there. Our suggested wording replaces ‘isolating’ with ‘initiating isolation of’, which results in ‘To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating initiating isolation of those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.’

2) Please revise the Facilities consistent with the revised Purpose in item 1 above. Our suggested wording replaces ‘isolating’ with ‘initiating isolation of’, which results in ‘Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating initiating isolation of those faulted Elements.’

3) Supplemental Material p13 at bullet (Option 1) states ‘…from an established Fault current baseline for Protection Systems at the bus under study, …’ Please clarify that the ‘bus under study’ is typically the BES bus at or above 100kV. We suggest adding ‘For a TO the busses under study are typically their list of BES busses at or above 100kV. For a GO or DP, the busses under study are typically the list of BES busses at or above 100kV which they connect to; such busses may well be owned by the TO.’ This should also help allay some concerns about intended scope.

4) Supplemental Material p13 bottom and top of p14 states ‘The baseline can be the Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect.’ Please delete ‘where not available’ as this is burdensome and inconsistent with the intended scope.

5) Supplemental Material p13: Please add another example to help GO understand what most likely needs to be coordinated across the GO-TO interface. We suggest adding it between ‘…its zone of protection.’ and ‘Based on stakeholder comments …’ and starting a new paragraph with your existing ‘Based on stakeholder comments …’ sentence. We suggest adding: ‘Also for example a GO would typically include the generator step-up transformer neutral time overcurrent on its H0 bushing because its fault current could change due to generator, transformer, or BES changes or a combination of them.’

Document Name:

Likes: 0

Dislikes: 0

David Thorne - PHI - Potomac Electric Power Co. - 1 -

Selected Answer:

Answer Comment:

The standard addresses the establishment of a process to develop/review settings and to implement the process. It does not address implementing the "settings" that result from the process. Should there be a requirement concerning implementation of revised settings?

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

CSU agrees with SMUD's Comments concerning a potentially more effective approach to PRC-027., but in regards to PRC-001 CSU has some small modifications that CSU thinks will clarify the intent of some verbiage in PRC-001.

1. R2.1 and R2.2 – "Protection System component failure that adversely impacts the Reliable Operation of the BES" should replace the verbiage currently in the standards which currently states "protective relay or equipment failure reduces system reliability." This uses defined terms that clarifies what is meant by this statement.

2. PRC-001-3, R1 – If the verbiage is not clarified using defined terms then there needs to be some clarification concerning "reduces system reliability". CSU recommends the above verbiage using defined terms to clarify this ambiguity.

Document Name:

Likes: 1 Colorado Springs Utilities, 3, Morgan Charles

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Morgan - Colorado Springs Utilities - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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manon paquet - manon paquet On Behalf of: Roger Dufresne, Hydro-Qu?bec Production, 1, 5

Selected Answer:

Answer Comment:

This draft of the standard is less limited than previous versions. It allows responsibles entities to establish a global process that meets their needs.

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

1) Please revise the Purpose because it implies the Protection System isolates the fault. The NERC defined Protection System includes the trip coil but stops there. Our suggested wording replaces ‘isolating’ with ‘initiating isolation of’, which results in ‘To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating initiating isolation of those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.’

2) Please revise the Facilities consistent with the revised Purpose in item 1 above. Our suggested wording replaces ‘isolating’ with ‘initiating isolation of’, which results in ‘Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating initiating isolation of those faulted Elements.’

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may well be owned by the TO.' This should also help allay some concerns about intended scope.

4) Supplemental Material p13 bottom and top of p14 states 'The baseline can be the Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect.' Please delete 'where not available' as this is burdensome and inconsistent with the intended scope.

5) Supplemental Material p13: Please add another example to help GO understand what most likely needs to be coordinated across the GO-TO interface. We suggest adding it between '…its zone of protection.' and 'Based on stakeholder comments …' and starting a new paragraph with your existing 'Based on stakeholder comments …' sentence. We suggest adding: 'Also for example a GO would typically include the generator step-up transformer neutral time overcurrent on its H0 bushing because its fault current could change due to generator, transformer, or BES changes or a combination of them.'

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 3, Poston James

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

1) Please revise the Purpose because it implies the Protection System isolates the fault. The NERC defined Protection System includes the trip coil but stops there. Our suggested wording replaces 'isolating' with 'initiating isolation of', which results in 'To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating initiating isolation of those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.'

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5) Supplemental Material p13: Please add another example to help GO understand what most likely needs to be coordinated across the GO-TO interface. We suggest adding it between '…its zone of protection.' and 'Based on

stakeholder comments …' and starting a new paragraph with your existing 'Based on stakeholder comments …' sentence. We suggest adding: 'Also for example a GO would typically include the generator step-up transformer neutral time overcurrent on its H0 bushing because its fault current could change due to generator, transformer, or BES changes or a combination of them.'

The comments expressed herein represent a consensus of the views of the above-named members of the SERC PCS only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 3, Poston James

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

As indicated in a number of our previous comments, we continue to disagree with the treatment to Requirement R1 in the proposed PRC-001-3.

Requirement R1, as written, is not measurable and should be rescinded or mapped into another standard. While revising PRC-001-3 to reflect the mapping of certain requirements (e.g. R3) to PRC-027 is necessary, not revising other requirements that are unclear or unnecessary in the same standard that is being revised fails to take advantage of the opportunity of an initiated project. Quite simply, familiarity with and knowledge of the purpose and limitations of Protection System schemes applied in an operating entity's area are inherent to the entities that are required to comply with the rest of PRC-001-2. R1, therefore, is redundant and unnecessary. In addition, this requirement is not measurable. An analogy to this argument is that an RC needs to monitor its system conditions against IROLs. Since the RC is already required to prevent exceedances of IROLs

	and to apply mitigating measures to reduce flows to below IROLs within Tv, having monitoring capability is inherent to achieving these objectives. Hence in IRO-009-1, there are no requirements that stipulate the need to monitor flows/conditions against IROLs. **The above view is consistent with the Independent Experts Review Panel's recommendation. If the SDT continues to opine that the retirement of PRC-001-2 R1 Requirement falls outside the scope of this project, then we would suggest the SDT to immediately submit an addendum or revised SAR to the Standards Committee for approval to post for industry comment, then revise/remove R1 accordingly.** **We offered a similar comment about a year ago when the proposal was to keep only R1 in PRC-001 until this requirement is incorporated into a PER standard. No actions have been taken since. Had an addendum SAR or a revised SAR been posted then, the PRC-001-2 R1 issue would have been fully addressed by now. We are disappointed that over this period, neither NERC staff nor the PRC-027 SDT took the proactive action to proactively address/close out the issue. Today, we still have a requirement that is improper and not measurable. Once again, we urge NERC staff and the SDT to act now to post an addendum SAR or a revised SAR to fully resolve this issue. Further delay in addressing the issue until a new project is initiated may result in dragging the approval of PRC-027-1 for another several months to a year.(Note – The last paragraph of these SRC comments represent a consensus of the ISOs/RTOs with the exception of ERCOT.)**
Document Name:	
Likes:	0
Dislikes:	0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

ERCOT supports the comments regarding removal and/or revision of Requirement R1 in PRC-001-1.1.

Document Name:

Likes: 0

Dislikes: 0

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 OGE Energy - Oklahoma Gas and Electric Co., 5, Staples Leo

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer:

Answer Comment:

Supplemental Material section 1.3, page 13/16 first bulleted paragraph (Option 1). The first two sentences are unclear, the clause starting with "or, Fault" and ending with "over time" and the following sentence starting with "the accumulation" are confusing.

Requirement R1 uses the words "to operate in the intended sequence during Faults" which makes sense for TOs but is not as clear for a GO/GOP. The SDT should attempt to address what, if anything, this means to a GO. Do GOs have to define this for faults at various locations on the transmission lines, inside the plant etc.? In general, this draft of PRC-027-1 is not clear enough for a Generator Owner (GO). The requirements applicable to a GO need to be clearly defined.

During the webinar, presenters talked about other GO relays other than distance and overcurrent, being in the scope of this standard. If that is the case, these should be clearly included in this standard and requirements for coordination should be part of this standard.

During the webinar, the presenters referred to coordination requirements discussed in IEEE standards and NERC SPCS Technical Reference Document (TRDs). Based on the response to questions asked by Exelon on the Webinar, it appears the SDT expects a GOs to implement some recommendations from IEEE guides or NERC TRDs which do not have the force of law and are not included in the requirements. The question was posed during the Webinar Q&A, "if a GO does not have protective relays which are dependent on the magnitude of fault current, then do they [drafting team] agree this standard is not applicable to the GO". The response was that there are coordination requirements in IEEE standards and NERC TRD which a GO has to address. We disagree with that explanation. IEEE Guides and NERC Technical Reference Document have good guidance but are not enforceable. The way the question was answered implies that this standard requires a GO, under the conditions as stated above, to comply with the requirements. This should not be left to Auditors interpretation. We request the drafting team clarify the requirements to address this issue.

Document Name:

Likes: 0

Dislikes: 0

John Bee - Exelon - 3 -

Selected Answer:

Answer Comment:

See Exelon TO comments as submitted by C Scanlon for exelon

Document Name:

Likes: 0

Dislikes: 0

Vince Catania - Exelon - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dave Carlson - Exelon - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

This standard is a step in the right direction and appreciate the efforts of the drafting team. Consideration should be given to schemes not impacted by changes in fault current. Perhaps language could be added that requires review of the schemes associated with any activity that changes the impedance characteristics of a BES line or transformer. Otherwise, schemes that are indifferent to changes in fault current (i.e. step-distance and differential) should be excluded from the current requirements, and should be subject to review as noted above or the drafting team should provide a technical basis for a 6-year review cycle.

Document Name:

Likes: 0

Dislikes: 0

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

1. R1.1: Recommend expanding on existing language in the Rational/ Technical Guidelines to emphasize that 'method to review and update' is not a detailed verification of the entire model on a regular basis but a localized review where work is being done going forward.

2. R1.4: Recommend expanding on existing language in the Rational/ Technical Guidelines to indicate that this may be a simple gut check or could be a full review based on the scope of the project and/or the experience of the person doing the work. In either case, the scope of the review is up to the entity.

3. The Rational box for R1.3 correctly indicates that ‘The Fault current-based option requires an entity to first establish a Fault current baseline for Protection Systems at the bus under study to be used as a control point for future Fault current studies”; however, there is no requirement to establish such in the requirements nor in the Implementation Plan. As such, it seems like an entity could establish such a baseline sometime in the future and then make the comparison in the 60th month. As such the standard should clearly require an entity that plans to use the methodology stated in first bullet of 1.3 must establish a baseline prior to the effective date of the Standard. This could be accomplished with a new requirement in R1.3 or possibly in the Implementation Plan.

4. In the VSL tables, the second part of the OR statements for R1 and R2 are not needed and should be deleted. The first part of the OR statement includes the words “two or more”. The phase ‘or more’ includes ‘all elements’ which equates to failing to establish a review process at all.

5. There appears to be some indention/ formatting issues within the Supplemental material for R.1.3 and R.1.4.

6. During the NERC Webinar is was noted that the Supplemental material section states “The baseline can be the Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect.” It was indicated that the language might lead an auditor to ask for evidence that an entity researched for this data. Perhaps simply remove the words ‘where available’?

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

None.

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

We wish to express support for the direction the Standard Drafting Team has taken in this major re-write to formulate Draft 5 of the standard. Some clarifications and extension of the Implementation Plan, as noted in the comments, are all that should suffice to arrive at a future successful draft standard.

The approach that the System Protection Coordination Standard Drafting Team (SPCSDT) has taken by establishing a separate standard for Coordination of Protection System Performance During Faults (PRC -027), while another standard for protection coordination (PRC-001-3 System Protection Coordination) already exists creates an unnecessary administrative burden. The attributes of coordinating fault protection should be contained in a standard on System Protection Coordination. The argument is being made that other protection systems (UFLS, UVLS) have their own standards, and therefore fault clearing should have its own standard. There is an opportunity to consolidate and be less administrative by having only one standard.

Document Name:

Likes: 1 Hydro-Qu?bec TransEnergie, 1, Phan Si Truc

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Section 4.2 should more clearly address the applicable generator Facilities, and FMPA suggests that it mirror the latest version of PRC-005, specifically section 4.2.5.

R1 refers to "BES Protection Systems" which could be interpreted in various ways, including those that go beyond what is described in the applicability section. FMPA suggests replacing the phrase “BES Protection Systems” in R1 with “Protection Systems identified in section 4.2”.

FMPA also recommends a rephrasing of R1 to make it more grammatically correct…”establish a process to develop settings for its Protection Systems identified in section 4.2 so that they operate in the intended sequence during Faults.”

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

1) Please consider revising the A.3 Purpose statement, and the A.4.2 Facilities statement, because they imply the Protection System isolates the fault. The NERC definition of “Protection System” includes the trip coil, but stops there. We suggest replacing “isolating” with “initiating isolation of” in both statements.

2) Supplemental Material p13 at bullet (Option 1) states “…from an established Fault current baseline for Protection Systems at the bus under study, …” Please clarify that the “bus under study” is typically the BES bus at or above 100kV. We suggest adding “For a TO the busses under study are typically their list of BES busses at or above 100kV. For a GO or DP, the busses under study are typically the list of BES busses at or above 100kV which they connect to; such busses may well be owned by the TO.” This should also help allay some concerns about intended scope.

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Document Name:

Likes: 0

Dislikes: 0

Leo Staples - OGE Energy - Oklahoma Gas and Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE requests clarification of the VSLs to explain if a "Part" is referring to a requirement or subrequirement. If it is referring to a subrequirement, Texas RE suggests specifically stating the subrequirement.

Texas RE suggests a thorough grammatical and consistency review on PRC-027-1 and PRC-001-3. Texas RE noticed the following:

- "The the" in Section 1.2 is duplicated;

- The timeframes and terminology are not consistent with the Rules of Procedure, risk-based compliance process, or the Glossary of Terms; and
- The VSL/VRF Levels are inconsistent with other standards being reviewed. There are not any "Levels of Non-Compliance for Generator Operators" but there are requirements for Generator Operators to follow. Is this because there are no "Measures" for those requirements with GOP responsibility? If there is not an adjustment to the VRF/VSL format, "Levels of Non-Compliance for Transmission Operators" in PRC-001-3, section 3.4 referring to Level 4 does not make sense.

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brown - Santee Cooper - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lewis Pierce - Santee Cooper - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

James Poston - Santee Cooper - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Why is PRC-001-1.1 R5 (i.e. the new R3) not being deleted as part of this project? It focuses on Protection System coordination as well.

Why did the drafting team leave PRC-001 R1 in effect? The words “familiar with” have been interpreted to be a training requirement. This should be retired as PER-005-2 would capture this requirement in the systematic approach to training.

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

We are curious as to why the SDT has developed a Standard that requires establishing a “process” rather than a “methodology” which is more consistent with other Standards such as FAC and TPL for example (SOL Methodology, Facility Rating Methodology, etc.) Typically in the Standards, processes are included within plans and methodologies. In this Standard there seems to be a shift to a method within a process. We are curious if there is a specific, intended difference in the use of the “process” term.

Also, we would suggest capitalizing the terms ‘transmission’ and ‘load’ in Requirement R3 and sub-part R3.1 in PRC-001-3 standard as they are both defined in the NERC Glossary of Terms. Also, we would ask the drafting to provide clarity on why there are only two Measurements while there four Requirements in the standard.

Document Name:

Likes: 0

Dislikes: 0

Shannon Fair - Colorado Springs Utilities - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: "To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those Faults, such that the Protection Systems operate in the intended sequence during Faults." PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii).

Completed Actions	Date
Standard Authorization Request (SAR) posted for comment	June 11 – July 10, 2007
SAR approved	August 13, 2007
Draft 1 of PRC-001-2 posted for comment	September 11 – October 26, 2009
Draft 1 of PRC-027-1 posted for formal comment with ballot	May 21 – July 5, 2012
Draft 2 of PRC-027-1 posted for formal comment with ballot	November 16 – December 17, 2012
Draft 3 of PRC-027-1 posted for formal comment with ballot	June 4 – July 3, 2013
Draft 4 of PRC-027-1 posted for formal comment with ballot	November 4 – December 31, 2013
Draft 5 of PRC-027-1 posted for informal comment	October 1 – October 21, 2014
Draft 5 of PRC-027-1 posted for formal comment with ballot	April 1 – May 15, 2015
Draft 6 of PRC-027-1 posted for formal comment with ballot	July 29 – September 11, 2015

Anticipated Actions	Date
10-day final ballot	October, 2015
NERC Board of Trustees (BOT) adoption	November, 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Protection System Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Protection System Issues Addressed by Other Reliability Standards:

Fault clearing is the only aspect of protection coordination addressed by Reliability Standard PRC-027-1. Including aspects of protection coordination other than Fault coordination would cause duplication or conflict with the requirements of other Reliability Standards. Specifically, other protection issues, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following Reliability Standards:

- Underfrequency Load shedding programs are addressed in PRC-006-2.
- Undervoltage Load shedding programs are addressed in PRC-010-1.
- Generator performance during declined frequency and voltage excursions is addressed in PRC-024-1.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-1.
- Transmission relay loadability is addressed in PRC-023-3.
- Generator relay loadability is addressed in PRC-025-1.
- Protective relay response during stable power swings is addressed in PRC-026-1.
- Protection System Misoperations (including those caused by coordination issues) are addressed in PRC-004-3.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Coordination of Protection Systems for Performance During Faults**
2. **Number:** PRC-027-1
3. **Purpose:** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Owner
     - **4.1.2.** Generator Owner
     - **4.1.3.** Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 below)
   - **4.2. Facilities:** Protection Systems installed to detect and isolate Faults on BES Elements.
5. **Effective Date:** See the Implementation Plan for PRC-027-1, Project 2007-06 System Protection Coordination.

B. Requirements and Measures

Rationale for Requirement R1:

Coordinated Protection Systems enhance reliability by isolating faulted equipment, thus reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. The stated purpose of this standard is: "To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those Faults, such that the Protection Systems operate in the intended sequence during Faults." Requirement R1 captures this intent by requiring responsible entities establish a process that, when followed, allows for their Protection Systems to operate in the intended sequence during Faults. Requirement R1, Parts 1.1 through 1.3 are key elements to the process for developing Protection System settings.

Part 1.1 Reviewing and updating the short-circuit models used to develop new or revised Protection System settings helps to assure that settings are developed using accurate, up-to-date information.

Part 1.2 A review of the developed Protection System settings reduces the likelihood of introducing human error and verifies that the settings produced meet the technical criteria of the entity. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of reviews.

Part 1.3 The coordination of Protection Systems associated with BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) is essential to the reliability of the BES. Communication and review of proposed settings among these entities are necessary to identify potential coordination issues and address the issues prior to implementation of any proposed Protection System changes.

Unforeseen circumstances could require immediate changes to Protection System settings. Requirement R1, Part 1.3.4 requires owners to include a procedure to communicate those unplanned settings changes after-the-fact to the other owner(s) of the electrically-joined Facilities.

Note: In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A review and update of short-circuit models for the BES Elements under study.

1.2. A review of the developed Protection System settings.

1.3. For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.3.1. Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

1.3.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

1.3.3. Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

1.3.4. Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:

1.3.4.1. Implementation or commissioning.

1.3.4.2. Misoperation investigations.

1.3.4.3. Maintenance activities.

1.3.4.4. Emergency replacements required as a result of Protection System component failure.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity established a process to develop settings for its Protection Systems, in accordance with Requirement R1.

Rationale for Requirement R2:

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities (Transmission Owners, Generator Owners, and Distribution Providers) to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. The numerical identifiers in Attachment A represent general protective device functions per ANSI/IEEE *Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Requirement R2 provides responsible entities with options to assess the state of their Protection System coordination.

Option 1 is a time-based methodology. The entity may choose to perform, at least once every six years, a Protection System Coordination Study for each of its BES Protection Systems identified as being affected by changes in Fault current. The six calendar year time interval was selected as a balance between the resources required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

Option 2 is a Fault current based methodology. If Option 2 is initially selected, Fault current baseline(s) must be established prior to the effective date of this Reliability Standard. A baseline may be established when a new Element is installed or after a Protection System Coordination Study has been performed. The baseline(s) will be used as control point(s) for future Fault current comparisons. The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators. At least once every six calendar years following the effective date of this standard, the entity will perform a Protection System Coordination Study when its Fault current comparison identifies a 15 percent or greater deviation in Fault current values (either three-phase or phase-to-ground) at each bus to which the Element is connected. The baseline Fault current value(s) will be re-established whenever a new Protection

System Coordination Study is performed. Fault current changes on the System not directly associated with BES modifications are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection System functions (identified in Attachment A of this standard) during Fault conditions. A Fault current deviation threshold of 15 percent or greater (as compared to the established baseline) and a maximum time interval of six calendar years were chosen for these evaluations. These parameters provide an entity with latitude to choose a Fault current threshold and time interval that best match its protection philosophy, Protection System maintenance schedule, or other business considerations, without creating risk to reliability (See the Supplemental Material section for more detailed discussion).

The footnote in Option 2 describes how an entity may change from a time-based option to a Fault current based option for existing Elements when performing Protection System Coordination Studies. The footnote also allows for the creation of a baseline when a Protection System Coordination Study is performed for installing new Elements.

Option 3 provides the entity the choice of using both the time-based and Fault current based methodologies. For example, the entity may choose to utilize the time-based methodology for Protection Systems at more critical Facilities and use the Fault current based methodology for Protection Systems at other Facilities.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years;[1] or,
- Option 3: A combination of the above.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity performed Protection System Coordination Study(ies) and/or Fault current comparisons in accordance with Requirement R2.

[1] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline by performing a Protection System Coordination Study.

Rationale for Requirement R3:

Utilizing the processes established in Requirement R1 to develop new and revised Protection System settings provides a consistent approach to the development of Protection System settings and will minimize the potential for errors.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity utilized its settings development process established in Requirement R1, as specified in Requirement R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance with Requirements R1, R2, and R3, and Measures M1, M2, and M3 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 or Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.3. OR The responsible entity failed to establish any process in accordance with Requirement R1.
R2.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3 but was late by less than or equal to 30 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 90 calendar days. OR The responsible entity failed to perform Option 1, Option

				2, or Option 3, in accordance with Requirement R2.
R3.	N/A	N/A	N/A	The responsible entity failed to utilize the process established in accordance with Requirement R1.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee – "Power Plant and Transmission System Protection Coordination."

NERC System Protection and Control Task Force, December 7, 2006, "Assessment of Standard PRC-001-0 – System Protection Coordination."

NERC System Protection and Control Task Force, September 2006, "The Complexity of Protecting Three-Terminal Transmission Lines."

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	New standard developed under Project 2007-06

Attachment A

The following Protection System functions[2] are applicable to Requirement R2 if available Fault current levels are used to develop the settings for those Protection System functions:

21 – Distance if:

- infeed is used in determining reach (phase and ground distance), or
- zero-sequence mutual coupling is used in determining reach (ground distance).

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent

67 – AC directional overcurrent if used in a non-communication-aided protection scheme

Notes:

1. The above Protection System functions are susceptible to changes in the magnitude of available short-circuit Fault current. These functions utilize current in their measurement to initiate tripping of circuit breakers. The functions listed above are included in a Protection System Coordination Study because they require coordination with other Protection Systems.
2. See the PRC-027-1 Supplemental Material section for additional information.

[2] ANSI/IEEE Standard C37.2 *Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Purpose

The Purpose states: To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.

Coordinated Protection Systems enhance reliability by isolating faulted equipment, reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. This standard requires that entities establish and implement a process to coordinate their BES Protection Systems to operate in the intended sequence during Faults.

Applicability

Transmission Owners, Generator Owners, and Distribution Providers are included in the Applicability of PRC-027-1 because they may own Protection Systems that are installed for the purpose of detecting Faults on the Bulk Electric System (BES). It is only those Protection Systems that are under the purview of this standard.

Transmission Owners are included in the Applicability of PRC-027-1 because they own the largest number of Protection Systems installed for the purpose of detecting Faults on the BES.

Generator Owners have Protection Systems installed for the purpose of detecting Faults on the BES. It is important that those Protection Systems are coordinated with Protection Systems owned by Transmission Owners to ensure that generation Facilities do not become disconnected from the BES unnecessarily. Functions such as impedance reaches, overcurrent pickups, and time delays need to be evaluated for coordination.

A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.

After the Protection Systems of Distribution Providers and Generator Owners are shown to be coordinated with other Protection Systems on the BES, there will be little future impact on the entities unless there are significant changes at or near the bus that interconnects with the Transmission Owner. The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current availability upon request by the Distribution Provider or Generator Owner. The Distribution Provider and Generator Owner will determine whether a change in Fault current from the baseline has occurred such that a review of coordination is necessary.

Requirement R1

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults.

The reliability objective of this requirement is to have applicable entities establish a process to develop settings for coordinating their BES Protection Systems, such that they operate in the intended sequence during Faults. The parts that are included as elements of the process ensure the development of accurate settings, as well as providing internal and external checks to minimize the possibility of errors that could be introduced in the development of settings.

This standard references various publications that discuss protective relaying theory and application. The description of "coordination of protection" is from the IEEE Standard C37.113-1999 (Reaffirmed: 2004), *Guide for Protective Relay Applications to Transmission Lines*, which reads:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Entities may have differing technical criteria for the development of Protection System settings based on their own philosophies. These philosophies can vary based on system topology, protection technology utilized, as well as historical knowledge; as such, a single definition or criterion for "Protection System coordination" is not practical.

The coordination of some Protection Systems may seem unnecessary, such as for a line that is protected solely by dual current differential relays. However, backup Protection Systems that are enabled to operate based on current or apparent impedance with some definite or inverse time delay must be coordinated with other Protection Systems of the Element such that tripping does not unnecessarily occur for Faults outside of the differential zone.

Part 1.1 A review and update of short-circuit models for the BES Elements under study.

The study used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers is the short-circuit study. Including a review and, if necessary, an update of short-circuit study information is necessary to ensure that information accurately reflects the physical power system that will form the basis of the Protection System Coordination Study and development of Protection System relay settings. The results of a short-circuit study are only as accurate as the information that its calculations are based on.

A short-circuit study is an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical Fault. Because the results of short-circuit studies are used as the basis for protective device coordination studies, the short-circuit model should accurately reflect the physical power system.

Reviews could include:

1. A review of applicable BES line, transformer, and generator impedances.

2. A review of the network model to confirm the network in the study accurately reflects the configuration of the actual System, or how the System will be configured when the proposed relay settings are installed.
3. A review, where applicable, of interconnected Transmission Owner, Generator Owner, and Distribution Provider information.

Part 1.2 A review of the developed Protection System settings.

A review of the Protection System settings prior to implementation reduces the possibility of introducing human error. A review is any systematic process of verifying the developed settings meet the technical criteria of the entity. Examples of reviews include peer reviews, automated checking programs, and entity-developed review procedures.

Part 1.3 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

Requirement R1, Part 1.3 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities. Communication among these entities is essential so potential Protection System coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

Part 1.3.1 1.3.1. Provide the proposed Protection System settings to the owners of the electrically-joined Facilities.

Requirement R1, Part 1.3.1 requires the entity to include in its process a provision to provide proposed Protection System settings to other entities. This communication ensures that the other entities have the necessary information to review the settings and determine if there are any Protection System coordination issues.

Part 1.3.2 Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

Requirement R1, Part 1.3.2 requires the entity receiving proposed Protection System settings to include in its process a provision to respond to the entity that initiated the proposed changes. This ensures that the proposed settings are reviewed and that the initiating entity receives a response indicating Protection System coordination issues were identified, or affirmation that no issues were identified.

Part 1.3.3 Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Requirement R1, Part 1.3.3 requires the entity to include in their process a provision to verify that any identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation. This ensures that any potential impact to BES reliability is minimized.

Note: There could be instances where coordination issues are identified and the entities agree not to mitigate all of the issues based on engineering judgement. It is also recognized that coordination issues identified during a project may not be immediately resolved if the resolution involves additional system modifications not identified in the initial project scope. Further, there could be situations where protection philosophies differ between entities, but the entities can agree that these differences do not create coordination issues.

Part 1.3.4 Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:

1.3.4.1. Implementation or commissioning.

1.3.4.2. Misoperation investigations.

1.3.4.3. Maintenance activities.

1.3.4.4. Emergency replacements required as a result of Protection System component failure.

Requirement R1, Part 1.3.4 requires the entity to communicate revisions to Protection System settings that occur due to unforeseen circumstances and differ from those developed during the planning stages of projects.

Requirement R2

This requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A:

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years;[3] or,
- Option 3: A combination of the above.

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. Two triggers were established for initiating a review of existing Protection System settings to allow for industry flexibility.

[3] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline by performing a Protection System Coordination Study.

In the first option, an entity may choose a time-based methodology to review Protection System settings, thus eliminating the necessity of establishing a Fault current baseline and periodically performing Fault current comparisons. This option provides the entity the flexibility to choose an interval of up to six calendar years for performing the Protection System Coordination Studies for those Protection System functions in Attachment A. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which an Element is connected. This option allows the entity to choose an interval of up to six calendar years to perform the Fault current comparisons and Protection System Coordination Studies. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. A maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) was established based on generally-accepted margins for setting Protection Systems in which incremental Fault current changes would not interfere with coordination. The 15 percent maximum deviation provides an entity with latitude to choose a Fault current threshold that best matches its protection philosophy, or other business considerations. The Fault current based option requires an entity to first establish a Fault current baseline to be used as a point of reference for future Fault current studies. The Fault current values used in the percent change calculation, whether three-phase or phase-to-ground Fault currents, are typically determined with all generation in service and all transmission BES Elements in their normal operating state.

An entity that elects to use Option 2 following the effective date of the standard, must establish its baseline prior to the effective date. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline upon performing a Protection System Coordination Study. The Fault current values used in the original baseline can be updated or created when a Protection System Coordination Study is performed. The baseline values at each bus to which an Element is connected are updated whenever a new Protection System Coordination Study is performed for the subject Protection System.

> **Example:** An initial baseline is established at 10,000 amps. During the first short-circuit review, it is discovered that Fault current has increased to 11,250 amps (12.5 percent change); consequently, no Protection System Coordination Study is required since the increase is below the maximum 15 percent deviation. The baseline value for the next study remains at 10,000 amps because no study was performed. However, during the next Fault current comparison, the Fault current has increased to 11,500 (15 percent change); therefore, a Protection System Coordination Study is required, and a new baseline of 11,500 amps would be established.

> **Note:** In the first review described above, if the entity decides to perform a Protection System Coordination Study at the 12.5 percent deviation and the results of the study indicate that the settings still meet the setting criteria of the entity, then no settings changes are required and the baseline Fault current(s) would be updated.

As a third option, an entity has the flexibility to apply a combination of the two methodologies. For example, an entity may choose the periodic Protection System review (Option 1) and review its Facilities operated above 300 kV on a six year interval, while choosing to use the Fault current comparison (Option 2) for its Facilities operated below 300 kV.

Attachment A identifies the Protection System functions susceptible to changes in the magnitude of available short-circuit Fault current. These functions utilize AC current in their measurement to initiate tripping of circuit breakers. The numerical identifiers in Attachment A represent general device functions according to *ANSI/IEEE Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*. The device functions listed in Attachment A are to be reviewed provided they require coordination with other Protection Systems. The following scenarios provide some examples for applying Attachment A.

A “51 – AC inverse time overcurrent” relay connected to a CT on the neutral of a generator step-up transformer, referred to as “51N – AC Inverse Time Earth Overcurrent Relay (Neutral CT Method)” in ANSI/IEEE Standard C37.2, would be included in a Protection System Coordination Study. Also applicable, are “51 – AC Inverse time overcurrent” relays connected to CTs on the phases of an autotransformer for through-fault protection. Overcurrent functions used in conjunction with other functions are to be reviewed as well. An example is a definite-time overcurrent function, which is a “50 – Instantaneous overcurrent” function used in conjunction with a “62 – Time-delay” function.

If the functions listed in Attachment A are used in conjunction with other functions, they would be included in a Protection System Coordination Study provided they require coordination with other Protection Systems. An example of this is a time-delayed “21 – Distance” function, which is a “21 – Distance” function with a “62 – Time-delay” function. Another example would be a definite-time overcurrent function, which is a “50 – Instantaneous overcurrent” function with a “62 – Time-delay” function. A “50 – Instantaneous overcurrent” function used for supervising a “21 – Distance” function would <u>not</u> be included in a Protection System Coordination Study as it does not require coordination with other Protection Systems.

Reviewing “21 – Distance” functions is limited to those applied for phase and ground distance where infeed is used in determining the phase or ground distance setting when zero-sequence mutual coupling is used in determining the setting. Where infeed is <u>not</u> used in determining the setting, “21 – Distance” functions would <u>not</u> be included in a Protection System Coordination Study, as the reach is not susceptible to changes in the magnitude of available short-circuit Fault current. Where infeed is used in determining the reach, coordination can be affected by changes in the magnitude of available short-circuit Fault current. Two examples where infeed may be used in determining the reach, are protection for a transmission line with a long tap and a three-terminal transmission line. Ground distance functions are influenced by zero-sequence mutual coupling. The ground distance measurement can appear to be greater than or less than the true distance to a Fault when there is zero-sequence mutual coupling. The influence of zero-sequence mutual coupling changes with the magnitude of available short-circuit current. Therefore, "21 – Distance" functions would be included in a Protection System Coordination Study, when zero-sequence mutual coupling is used in determining the setting.

Requirement R3

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

The reliability objective of this requirement is for applicable entities to utilize the process established in Requirement R1. Utilizing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, decreases the possibility of introducing errors, and increases the likelihood of maintaining a coordinated Protection System.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes will be moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: "To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those ~~faulted Elements~~Faults, such that the Protection ~~System components~~Systems operate in the intended sequence during Faults." PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii).~~ Draft 5 of PRC-027-1 modifies the applicability of the standard to include "Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements," whereas, prior drafts of the standard limited the applicability to "Protection Systems installed for the purpose of detecting Faults on Interconnecting Elements." With this change to the applicability, the coordination of Protection Systems for all "internal" or "intra-entity" connections between BES Elements are addressed.~~

Completed Actions	Date
Standard Authorization Request (SAR) posted for comment	June 11 – July 10, 2007
SAR approved	August 13, 2007
Draft 1 of PRC-001-2 posted for comment	September 11 – October 26, 2009
Draft 1 of PRC-027-1 posted for formal comment with ballot	May 21 – July 5, 2012
Draft 2 of PRC-027-1 posted for formal comment with ballot	November 16 – December 17, 2012
Draft 3 of PRC-027-1 posted for formal comment with ballot	June 4 – July 3, 2013~~.~~
Draft 4 of PRC-027-1 posted for formal comment with ballot	November 4 – December 31, 2013
Draft 5 of PRC-027-1 posted for informal comment	October 1 – October 21, 2014

Draft 5 of PRC-027-1 posted for formal comment with ballot	April 1 – May 15, 2015
Draft 6 of PRC-027-1 posted for formal comment with ballot	July 29 – September 11, 2015

Anticipated Actions	Date
10-day final ballot	~~June~~October, 2015
NERC Board of Trustees (BOT) adoption	~~August~~November, 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

~~N/A~~

Protection System Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Protection System Issues Addressed by Other ~~Projects~~Reliability Standards:

Fault clearing is the only aspect of protection coordination addressed by Reliability Standard PRC-027-1. ~~Other~~Including aspects of protection coordination other than Fault coordination would cause duplication or conflict with the requirements of other Reliability Standards. Specifically, other protection issues, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following ~~existing standards or current projects~~Reliability Standards:

- Underfrequency Load shedding programs are addressed in PRC-006-2.
- Undervoltage Load shedding programs are addressed in PRC-010-1.
- Generator performance during declined frequency and voltage excursions is addressed in PRC-024-1.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-1.
- Transmission relay loadability is addressed in PRC-023-3.
- Generator relay loadability is addressed in PRC-025-1.
- Protective relay response during stable power swings is addressed in PRC-026-1.
- Protection System Misoperations (including those caused by coordination issues) are addressed in PRC-004-3.

~~The SPCSDT contends that including aspects of protection coordination other than Fault coordination within PRC-027-1 would cause duplication or conflict with requirements and compliance measurements of other standards.~~

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Coordination of Protection ~~System~~Systems for Performance During Faults**

2. **Number:** PRC-027-1

3. **Purpose:** To maintain the coordination of Protection Systems installed ~~for the purpose of detecting~~to detect and isolate Faults on Bulk Electric System (BES ~~Elements and isolating those faulted~~) Elements, such that ~~the~~those Protection Systems operate in the intended sequence during Faults.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Owner

   4.1.2. Generator Owner

   4.1.3. Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 below)

   ~~**4.2.**~~ **Facilities:**

   4.2. Protection Systems installed ~~for the purpose of detecting~~to detect and isolate Faults on BES Elements ~~and isolating those faulted Elements~~.

   ~~**5.**~~ **Effective Date:**

5. See the Implementation Plan for PRC-027-1, Project 2007-06 System Protection Coordination.

B. Requirements and Measures

Rationale for Requirement R1:

Coordinated Protection Systems enhance ~~BES~~ reliability by isolating faulted equipment, thus reducing the risk of ~~power system~~BES instability or Cascading ~~by isolating the faulted equipment in a timely manner –~~, and leaving the remainder of the ~~System~~BES operational and more capable of withstanding the next ~~contingency~~Contingency. When Faults occur, properly coordinated ~~protection systems~~ Protection Systems minimize the number of ~~power system~~BES Elements that are removed from service and protect ~~power system~~ equipment from damage. The stated purpose of this standard is: "To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those ~~faulted Elements~~Faults, such that the Protection Systems operate in the intended sequence during Faults~~.~~." Requirement R1 captures this intent by ~~mandating an entity~~ requiring responsible entities establish a process that, when followed, ~~will facilitate consistent results~~allows for their Protection Systems to operate in the intended sequence during Faults. Requirement R1, Parts 1.1 through 1.3 are key elements to the process for developing ~~settings for its BES Protection Systems. The drafting team contends the parts listed below are essential elements of the coordination process~~Protection System settings.

Part 1.1 Reviewing and updating the ~~information required to coordinate Protection Systems maximizes the likelihood that the process of reviewing and developing~~ short-circuit models used to develop new or revised Protection System settings ~~is completed~~ helps to assure that settings are developed using accurate, up-to-date information. ~~Examples of information that potentially need to be reviewed are: short-circuit databases, line and transformer impedances, station configurations, current and voltage transformer ratios, adjacent Protection System settings, and relay and control functional drawings.~~

Part 1.2 ~~Reviewing~~A review of the ~~affected~~developed Protection System settings ~~when System changes occur maintains coordination. Examples of System changes are: new or revised Protection System installations, changes to a transmission system Element that alters any sequence or mutual coupling impedance, changes to generator unit(s) that result in a change in impedance, or changes to the generator step-up transformer(s) that result in a change in impedance.~~

~~**Part 1.3** Periodically reviewing Fault current values and/or existing entity-designated Protection System settings maximizes the likelihood that small incremental changes to the power system have not altered the coordination of the Protection Systems. Based on the Protection System design and/or susceptibility to changes in Fault current, applicable entities (Transmission Owners, Generator Owners, and Distribution Providers) will designate what Protection Systems must be included in the review(s) to ensure these Protection Systems continue to operate in the intended sequence during Faults. For example, a current differential scheme may not need to be included because changes in Fault current will not affect the coordination of this system. However, an instantaneous overcurrent element would need to be reviewed because changes in Fault current may cause this element to operate for Faults outside its zone of protection. Part 1.3 provides entities the flexibility to use a Fault current-based or a time-based methodology, or a combination of the two.~~

~~The Fault current-based option requires an entity to first establish a Fault current baseline for Protection Systems at the bus under study to be used as a control point for future Fault current studies. Fault current changes on the System are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. To minimize this risk, the drafting team chose a maximum Fault current deviation of 15 percent (as compared to the entity-established baseline) and a maximum time interval of six calendar years for the Fault current analysis to be performed. The drafting team contends these maximums provide an entity with latitude to choose a Fault current threshold and time interval that best matches its protection philosophy, Protection System maintenance schedule, or other business considerations. (See the Supplemental Materials section for more detailed discussion.)~~

~~As a second option, an entity may choose to establish a periodic review of its existing Protection System settings. The maximum time interval for the review is six calendar years. The drafting team assigned a six calendar year time interval because that corresponds to the maximum allowable maintenance period established for certain relays in PRC-005-2; consequently, this allows Protection System settings revisions to be included with associated maintenance.~~

~~As a third option, an entity may choose to apply a combination of the two review methodologies based on criteria such as voltage level or Protection System application.~~

~~**Part 1.4** A quality review of the Protection System settings minimizes the introduction of~~reduces the likelihood of introducing human error ~~into the development of Protection System settings and helps to ensure the~~ and verifies that the settings produced meet the ~~entity's design specifications for Protection System performance.~~technical criteria of the entity. Peer reviews, automated checking programs, and entity-developed review procedures~~,~~ are all examples of ~~quality~~ reviews.

Part 1.~~5~~3 The coordination of Protection Systems associated with BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) is ~~critical~~essential to the reliability of the BES. ~~Communications~~Communication and review of proposed settings among these entities ~~is essential so~~are necessary to identify potential coordination issues ~~can be identified~~ and ~~addressed~~address the issues prior to implementation of any proposed Protection System changes.

Unforeseen circumstances could require immediate changes to Protection System settings. Requirement R1, Part 1.3.4 requires owners to include a procedure to communicate those unplanned settings changes after-the-fact to the other owner(s) of the electrically-joined Facilities.

Note: In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process ~~to develop~~for developing new and revised Protection System settings for ~~its~~ BES Elements, such that the Protection Systems ~~to~~ operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A ~~method to~~ review and update of short-circuit models for the ~~information required to develop new or revised~~BES Elements under study.

~~**1.1.**~~**1.2.** A review of the developed Protection System settings.

~~**1.2.** A review of~~For Protection System settings ~~affected by System changes.~~

~~**1.3.** A review of existing entity-designated[1] Protection System settings based on one of the following:~~

- ~~**Periodic Fault current studies:** A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the bus under study, and evaluated in a time interval not to exceed six calendar years, or~~
- ~~**Periodic review of Protection System settings:** A time interval, not to exceed six calendar years, or~~
- ~~A combination of the above.~~

~~**1.4.** A quality review of the Protection System settings prior to implementation.~~

~~1.5.~~1.3. ~~For new or revised Protection System settings~~ applied on BES Elements that electrically join Facilities owned by separate functional entities~~,~~ (Transmission Owners, Generator Owners, and Distribution Providers), ~~procedures~~provisions to:

~~1.5.1.~~1.3.1. ~~Communicate~~Provide the proposed Protection System settings ~~with the other functional entities~~to the owner(s) of the electrically-joined Facilities.

~~1.5.2.~~1.3.2. ~~Review~~ Respond to any owner(s) that provided its proposed Protection System settings ~~provided by other functional entities, and respond regarding the proposed settings. The response should identify~~pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or ~~affirm~~affirming that no coordination issue(s) were identified.

~~1.5.3.~~1.3.3. Verify that ~~any~~ identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

1.3.4. Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:

1.3.4.1. Implementation or commissioning.

1.3.4.2. Misoperation investigations.

1.3.4.3. Maintenance activities.

1.3.4.4. Emergency replacements required as a result of Protection System component failure.

~~[1] Based on the Protection System design and/or susceptibility to changes in Fault current, applicable entities (Transmission Owners, Generator Owners, and Distribution Providers) will designate what Protection Systems must be included in the review(s) to ensure these Protection Systems continue to operate in the intended sequence during Faults.~~

M1. Acceptable evidence ~~includes~~may include, but is not limited to, dated electronic or ~~physical dated records~~hard copy documentation to demonstrate that the responsible entity established a process to develop settings for its ~~BES~~ Protection Systems, in accordance with Requirement R1.

Rationale for Requirement R2:

~~Implementing the process established in Requirement R1 ensures a consistent approach to the development of Protection System settings such that BES Protection Systems operate in the intended sequence during Faults.~~Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities (Transmission Owners, Generator Owners, and Distribution Providers) to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. The numerical identifiers in Attachment A represent general protective device functions per ANSI/IEEE *Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.*

Requirement R2 provides responsible entities with options to assess the state of their Protection System coordination.

Option 1 is a time-based methodology. The entity may choose to perform, at least once every six years, a Protection System Coordination Study for each of its BES Protection Systems identified as being affected by changes in Fault current. The six calendar year time interval was selected as a balance between the resources required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

Option 2 is a Fault current based methodology. If Option 2 is initially selected, Fault current baseline(s) must be established prior to the effective date of this Reliability Standard. A baseline may be established when a new Element is installed or after a Protection System Coordination Study has been performed. The baseline(s) will be used as control point(s) for future Fault current comparisons. The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators. At least once every six calendar years following the effective date of this standard, the entity will perform a Protection System Coordination Study when its Fault current comparison identifies a 15 percent or greater deviation in Fault current values (either three-phase or phase-to-ground) at each bus to which the Element is connected. The baseline Fault current value(s) will be re-established whenever a new Protection System Coordination Study is performed. Fault current changes on the System not directly associated with BES modifications are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection System functions (identified in Attachment A of this standard) during Fault conditions. A Fault current deviation threshold of 15 percent or greater (as compared to the established baseline) and a maximum time interval of six calendar years were chosen for these evaluations. These parameters provide an entity with latitude to choose a Fault current threshold and time interval that best match its protection philosophy, Protection System maintenance schedule, or other business considerations, without creating risk to reliability (See the Supplemental Material section for more detailed discussion).

The footnote in Option 2 describes how an entity may change from a time-based option to a Fault current based option for existing Elements when performing Protection System Coordination Studies. The footnote also allows for the creation of a baseline when a Protection System Coordination Study is performed for installing new Elements.

Option 3 provides the entity the choice of using both the time-based and Fault current based methodologies. For example, the entity may choose to utilize the time-based methodology for Protection Systems at more critical Facilities and use the Fault current based methodology for Protection Systems at other Facilities.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall ~~implement the process established in accordance~~, for each BES Element with ~~Requirement R1.~~Protection System functions identified in Attachment A: *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: ~~Operations~~Long-term Planning]*

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years;[2] or,
- Option 3: A combination of the above.

M2. Acceptable evidence ~~includes~~may include, but is not limited to, dated electronic or ~~physical dated records~~hard copy documentation to demonstrate that the responsible entity ~~implemented the process established in~~ performed Protection System Coordination Study(ies) and/or Fault current comparisons in accordance with Requirement R2.

[2] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline by performing a Protection System Coordination Study.

Rationale for Requirement R3:

Utilizing the processes established in Requirement R1 to develop new and revised Protection System settings provides a consistent approach to the development of Protection System settings and will minimize the potential for errors.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~M2.~~M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity utilized its settings development process established in Requirement R1, as specified in Requirement R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider ~~that owns Protection Systems designed to detect Faults on BES Elements~~ shall each keep data or evidence to show compliance with Requirements R1~~ and~~, R2, and R3, and Measures M1, M2, and ~~M2,~~M3 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

~~The~~ The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	~~N/A~~The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 or Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include ~~one~~Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include ~~two or more Parts~~Requirement R1, Part 1.3. OR The responsible entity failed to establish ~~a~~any process in accordance with Requirement R1.
R2.	~~N/A~~The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3 but was late by less than or equal to 30 calendar days.	~~N/A~~The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The responsible entity ~~implemented the process established~~performed a Protection System Coordination Study for each BES Element, in accordance with Requirement ~~R1~~R2, Option 1, Option 2, or Option 3, but ~~failed~~was late by more than 60 calendar days but less than or equal	The responsible entity ~~implemented the process established~~performed a Protection System Coordination Study for each BES Element, in accordance with Requirement ~~R1~~R2, Option 1, Option 2, or Option 3, but ~~failed to implement two or~~ was late by more ~~Parts~~than 90 calendar days.

			to ~~implement one Part~~90 calendar days.	OR The responsible entity failed to ~~implement the process established~~perform Option 1, Option 2, or Option 3, in accordance with Requirement ~~R1~~R2.
R3.	N/A	N/A	N/A	The responsible entity failed to utilize the process established in accordance with Requirement R1.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee – ~~Technical Reference Document~~ "Power Plant and Transmission System Protection Coordination~~" (the most current version).~~."

NERC System Protection and Control Task Force~~—~~, December 7, 2006, "Assessment of Standard PRC-001-0 – System Protection Coordination ~~(December 7, 2006)~~."

NERC System Protection and Control Task Force~~—~~, September 2006, "The Complexity of Protecting Three-Terminal Transmission Lines ~~(September 2006)~~."

~~Implementation Plan~~ ~~**(DELETE GREEN TEXT PRIOR TO PUBLISHING) A link should be added to the implementation plan and other important documents associated with the standard once finalized.**~~

Version History

Version	Date	Action	Change Tracking
1	~~TBD~~	Adopted by NERC Board of Trustees	~~New~~New standard developed under Project 2007-06

Attachment A

The following Protection System functions[3] are applicable to Requirement R2 if available Fault current levels are used to develop the settings for those Protection System functions:

21 – Distance if:

- infeed is used in determining reach (phase and ground distance), or
- zero-sequence mutual coupling is used in determining reach (ground distance).

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent

67 – AC directional overcurrent if used in a non-communication-aided protection scheme

Notes:

1. The above Protection System functions are susceptible to changes in the magnitude of available short-circuit Fault current. These functions utilize current in their measurement to initiate tripping of circuit breakers. The functions listed above are included in a Protection System Coordination Study because they require coordination with other Protection Systems.
2. See the PRC-027-1 Supplemental Material section for additional information.

[3] ANSI/IEEE Standard C37.2 *Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.*

Purpose~~:~~

The Purpose states: To maintain the coordination of Protection Systems installed ~~for the purpose of detecting~~to detect and isolate Faults on Bulk Electric System (BES ~~Elements and isolating those faulted~~) Elements, such that ~~the~~those Protection Systems operate in the intended sequence during Faults.

Coordinated Protection Systems enhance ~~BES~~ reliability by isolating faulted equipment, reducing the risk of ~~power system~~BES instability or Cascading ~~by isolating the faulted equipment in a timely manner –~~, and leaving the remainder of the ~~System~~BES operational and more capable of withstanding the next ~~contingency~~Contingency. When Faults occur, properly coordinated ~~protection systems~~Protection Systems minimize the number of ~~power system~~BES Elements that are removed from service and protect ~~power system~~ equipment from damage. This standard requires that entities establish and implement a process to coordinate their BES Protection Systems to operate in the intended sequence during Faults.

Applicability

Transmission Owners, Generator Owners, and Distribution Providers are included in the Applicability of PRC-027-1 because they may own Protection Systems that are installed for the purpose of detecting Faults on the Bulk Electric System (BES). It is only those Protection Systems that are under the purview of this standard.

Transmission Owners are included in the Applicability of PRC-027-1 because they own the largest number of Protection Systems installed for the purpose of detecting Faults on the BES.

Generator Owners have Protection Systems installed for the purpose of detecting Faults on the BES. It is important that those Protection Systems are coordinated with Protection Systems owned by Transmission Owners to ensure that generation Facilities do not become disconnected from the BES unnecessarily. Functions such as impedance reaches, overcurrent pickups, and time delays need to be evaluated for coordination.

A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.

After the Protection Systems of Distribution Providers and Generator Owners are shown to be coordinated with other Protection Systems on the BES, there will be little future impact on the entities unless there are significant changes at or near the bus that interconnects with the Transmission Owner. The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current availability upon request by the Distribution Provider or Generator Owner. The Distribution Provider and Generator Owner will determine whether a change in Fault current from the baseline has occurred such that a review of coordination is necessary.

Requirement R1~~:~~

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process ~~to develop~~for developing new and revised Protection System settings for ~~its~~ BES Elements, such that the Protection Systems ~~to~~ operate in the intended sequence during Faults.

~~This~~The reliability objective of this requirement ~~directs the~~is to have applicable entities ~~to~~ establish a process to develop settings for coordinating ~~its~~their BES Protection Systems, such that they operate in the intended sequence during Faults. The ~~drafting team contends the items~~parts that are included as elements of the process ~~are key to ensuring~~ensure the development of accurate settings, as well as providing internal and external checks to minimize the possibility of errors that could be introduced in the development of ~~these~~ settings.

~~In developing this Standard, the System Protection Coordination Standard Drafting Team (SPCSDT) referenced~~This standard references various publications that discuss protective relaying theory and application. The ~~following~~ description of "coordination of protection" is from the ~~pending revision of~~ IEEE Standard C37.113~~,~~-1999 (Reaffirmed: 2004), *Guide for Protective Relay Applications to Transmission Lines*, which reads:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

~~The drafting team acknowledges that entities~~Entities may have differing technical criteria for the development of Protection System settings based on their own ~~internal tolerances.~~philosophies. These philosophies can vary based on system topology, protection technology utilized, as well as historical knowledge~~. As~~; as such, a single definition or ~~criteria~~criterion for ~~'~~"Protection System ~~coordination'~~coordination" is not practical.

~~The drafting team also recognizes that the~~The coordination of some Protection Systems may seem unnecessary, such as for a line that is protected solely by dual current differential relays. ~~Where~~However, backup Protection Systems that are enabled to operate based on current ~~level~~ or apparent impedance with some definite or inverse time delay~~, it is important to ensure those~~ must be coordinated with other Protection Systems ~~coordinate with other Elements' Protection Systems~~of the Element such that tripping does not unnecessarily occur for Faults outside of the differential zone.

Part 1.1 A ~~method to~~ review and update of short-circuit models for the ~~information required to develop new or revised Protection System settings~~BES Elements under study.

~~Two important studies~~The study used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers ~~are~~is the short ~~-~~circuit study. Including a review and ~~protective device coordination studies. Having a method~~, if necessary, an update of ~~reviewing and updating~~short-circuit study information ~~to make sure it is correct in short circuit studies and protective device coordination studies~~ is necessary to ~~guarantee~~ensure that ~~these two studies~~ information accurately ~~reflect~~reflects the physical power system ~~being considered in~~that will form the basis of the Protection System Coordination Study and development of Protection System relay settings. The results of ~~the studies~~a short-circuit study are only as accurate as the information that ~~their~~its calculations are based on.

A short--circuit study is an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical Fault. ~~The~~Because the results of ~~a~~ short--circuit ~~study~~studies are used as the basis for protective device coordination studies~~. Because a~~, the short--circuit ~~study~~model should~~, as~~ accurately ~~as possible, model the actual network it is representing in order to calculate true Fault currents, the method of~~reflect the ~~review and update of information for the short circuit study might include the following:~~physical power system.

Reviews could include:

1. A review of applicable BES line, transformer, and generator impedances ~~to verify they are correct~~.
2. A review of the network model to confirm the network in the study accurately reflects the configuration of the actual ~~system~~System, or how the ~~system~~System will be configured when the proposed relay settings are installed.
3. A review, where applicable, of interconnected Transmission Owner, Generator Owner, ~~or~~and Distribution ~~Provider's~~Provider information ~~to determine whether their Systems are correctly modeled in the short circuit study~~.

~~A protective device coordination study is performed to determine the settings for protective relays to operate in the intended sequence during Faults. Protective device coordination studies are used to evaluate the application of protective devices, identify problem areas in the network, and determine solutions for existing or future device coordination.~~

~~A protective device coordination study should, as accurately as possible, represent the actual or proposed protective relaying in the network. The method for reviewing and updating information for the protective device coordination study might include the following:~~

~~1.~~ **Part 1.2** A review of ~~current and voltage transformer ratios,~~the developed Protection System settings ~~and the relay manufacture's curve characteristics to ensure the information in the protective device coordination study is correct~~.

~~2.~~ A review of the ~~adjacent relay settings to ensure those settings coordinate with the relay settings under study.~~

~~3. A review of interconnected Transmission Owner, Generator Owner, or Distribution Provider's actual and proposed relay setting changes to determine whether they are accurately represented in the protective device coordination study.~~

~~Other information that may be of value includes engineering drawings such as single-line diagrams, three-line diagrams, and relay and control functional drawings.~~

~~**Part 1.2** A review of Protection System settings affected by System changes.~~

~~Reviewing the affected Protection System settings when System changes occur maintains coordination. Examples of System changes are: new or revised Protection System installations, changes to a transmission system Element that alter any sequence or mutual coupling~~

~~impedance, changes to generator unit(s) that result in a change in impedance, or changes to the generator step-up transformer(s) that result in a change in impedance.~~

~~**Part 1.3** A review of existing entity-designated Protection System settings based on one of the following:~~

~~Periodically reviewing Fault current values and/or existing entity-designated Protection System settings maximizes the likelihood that small incremental changes to the power system have not altered the coordination of the Protection Systems. Based on the Protection System design and/or susceptibility to changes in Fault current, an entity will designate what Protection Systems must be included in the review to ensure these Protection Systems continue to operate in the intended sequence during Faults. For example, a current differential scheme may not need to be included because changes in Fault current will not affect the coordination of this system. However, settings for an instantaneous overcurrent element would need to be reviewed because changes in Fault current may cause this element to operate for Faults outside its zone of protection. Based on stakeholder comments and industry knowledge, the drafting team chose two 'triggers' for initiating a review of existing Protection System settings. Entities have the flexibility to use a Fault current-based or a time-based methodology, or a combination of the two.~~

- ~~(Option 1) A 15-percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the busunder study, and evaluated in a time interval not to exceed six calendar years, or Fault current changes on the System are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. To minimize this risk, the drafting team chose a maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) and a maximum time interval of six calendar years for the Fault current analysis to be performed. The drafting team contends these maximums provide an entity with latitude to choose a Fault current threshold and time interval that best matches its protection philosophy, Protection System maintenance schedule, or other business considerations. The Fault current-based option requires an entity to first establish a Fault current baseline to be used as a control point for future Fault current studies. The Fault current values used in the percent change calculation, whether three-phase or phase-to-ground Fault currents, are typically determined with maximum generation and all Facilities assumed to be in service.~~

~~The baseline can be the Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect. These baseline Fault current values can be at the bus level or at the individual Element level. When performing the periodic Fault current comparison, the entity would continue to compare actual Fault current values gathered during the review against the originally established baseline values until a condition occurs that necessitates the establishment of a new baseline.~~

~~Example: Baseline is established at 10,000 amps. During the first short-circuit review, it is discovered that Fault current has increased to 11,250 amps (12.5 % change); consequently, no Protection System settings review is required since the increase is below 15% and the baseline value for next review remains at 10,000 amps. However, during the next short-circuit review, the Fault current has increased to 11,500 (15% change); therefore, a review of the Protection System settings is required, and a new baseline of 11,500 amps would be established.~~

- ~~(Option 2) A time interval, not to exceed six calendar years, or~~

  ~~As a second option, an entity may choose a time-based methodology to review Protection System settings eliminating the necessity of establishing a Fault current baseline and periodically performing short-circuit studies. This option provides the entity the flexibility to choose an interval of up to six calendar years for performing the Protection System settings review.~~

- ~~(Option 3) A combination of the above.~~

  ~~As a third option, an entity has the flexibilityto apply a combination of the two methodologies based on criteria such as voltage level or Protection System applications. For example, an entity may choose the periodic Protection System review (option 2) and review its Facilities operated above 300 kV on a six year interval, while choosing to use the Fault current review (option 1) for its Facilities operated below 300 kV and periodically compare available Fault currents against the Fault current baseline.~~

~~**Part 1.4** A quality review of the Protection System settings prior to implementation.~~

~~A quality review of the~~ Protection System settings prior to implementation reduces the possibility of introducing human error~~ being introduced into the development of the Protection System settings. A quality review~~ . A review is any systematic process of verifying ~~that~~ the developed settings meet the ~~entity's specific requirements for Protection System performance. Peer~~technical criteria of the entity. Examples of reviews include peer reviews, automated checking programs, and entity-developed review procedures~~ are all examples of quality reviews~~.

Part 1.~~5~~3 For~~ new or revised~~ Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities~~,~~ (Transmission Owners, Generator Owners, and Distribution Providers), ~~procedures~~provisions to:

Requirement R1, Part 1.~~5~~3 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities. ~~Communications~~Communication among these entities is essential so potential Protection System coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

Part 1.~~5~~3.1 ~~Communicate~~1.3.1. Provide the proposed Protection System settings ~~with~~to the ~~other functional entities~~owners of the electrically-joined Facilities.

Requirement R1, Part 1.~~5~~3.1 ~~mandates entities have~~requires the entity to include in its process a ~~procedure~~provision to ~~communicate~~provide proposed Protection System settings ~~with~~to other entities. ~~These communications ensure~~This communication ensures that the other entities have the necessary information to review the settings and determine if there are any Protection System coordination issues.

Part 1.~~5~~3.2 ~~Review proposed Protection System settings~~ Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by ~~other functional entities, and respond regarding the proposed settings. The response should identify~~identifying any coordination issue(s) or ~~affirm~~affirming that no coordination issue(s) were identified.

Requirement R1, Part 1.~~5~~3.2 ~~mandates~~requires the entity receiving proposed Protection System settings ~~have~~to include in its process a ~~procedure to review the settings and~~provision to respond to the entity that initiated the proposed changes. This ensures that the proposed settings are reviewed and that the initiating entity receives a response~~. The response must include any identified~~ indicating Protection System coordination issues were identified, or ~~affirm~~affirmation that no issues were identified.

Part 1.~~5~~3.3 Verify that ~~any~~ identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Requirement R1, Part 1.~~5.~~3~~ mandates.~~3 requires the entity ~~have~~to include in their process a ~~procedure~~provision to verify that any identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation. This ensures that any potential impact to BES reliability ~~are~~is minimized.

~~The drafting team recognizes there~~Note: There could be instances where coordination issues are identified ~~that pose minimum risk to the reliability of the BES,~~ and the entities~~, therefore,~~ agree ~~to allow the unmitigated issue to remain~~not to mitigate all of the issues based on engineering judgement. It is also recognized that coordination issues identified during a project may not be immediately resolved if the resolution involves additional system modifications not identified in the initial project scope. ~~The drafting team also recognizes~~Further, there ~~are~~could be situations where ~~entities'~~ protection philosophies differ between entities, but ~~they~~the entities can agree that ~~there were no identified~~these differences do not create coordination issues.

Part 1.3.4 Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:

1.3.4.1. Implementation or commissioning.

1.3.4.2. Misoperation investigations.

1.3.4.3. Maintenance activities.

1.3.4.4. Emergency replacements required as a result of Protection System component failure.

Requirement R1, Part 1.3.4 requires the entity to communicate revisions to Protection System settings that occur due to unforeseen circumstances and differ from those developed during the planning stages of projects.

Requirement R2~~:~~

~~The~~This requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall ~~implement the process~~, for each BES Element with Protection System functions identified in Attachment A:

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or
- Option 2: Compare present Fault current values to an established ~~in accordance with Requirement R1.~~Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years;[4] or,
- ~~This requirement directs~~Option 3: A combination of the ~~applicable~~above.

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. Two triggers were established for initiating a review of existing Protection System settings to allow for industry flexibility.

In the first option, an entity may choose a time-based methodology to review Protection System settings, thus eliminating the necessity of establishing a Fault current baseline and periodically performing Fault current comparisons. This option provides the entity the flexibility to choose an interval of up to six calendar years for performing the Protection System Coordination Studies for those Protection System functions in Attachment A. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which an Element is connected. This option allows the entity to choose an interval of up to six calendar years to perform the Fault current comparisons

[4] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline by performing a Protection System Coordination Study.

and Protection System Coordination Studies. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. A maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) was established based on generally-accepted margins for setting Protection Systems in which incremental Fault current changes would not interfere with coordination. The 15 percent maximum deviation provides an entity with latitude to choose a Fault current threshold that best matches its protection philosophy, or other business considerations. The Fault current based option requires an entity to first establish a Fault current baseline to be used as a point of reference for future Fault current studies. The Fault current values used in the percent change calculation, whether three-phase or phase-to-ground Fault currents, are typically determined with all generation in service and all transmission BES Elements in their normal operating state.

An entity that elects to use Option 2 following the effective date of the standard, must establish its baseline prior to the effective date. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline upon performing a Protection System Coordination Study. The Fault current values used in the original baseline can be updated or created when a Protection System Coordination Study is performed. The baseline values at each bus to which an Element is connected are updated whenever a new Protection System Coordination Study is performed for the subject Protection System.

> **Example:** ~~implement the~~ An initial baseline is established at 10,000 amps. During the first short-circuit review, it is discovered that Fault current has increased to 11,250 amps (12.5 percent change); consequently, no Protection System Coordination Study is required since the increase is below the maximum 15 percent deviation. The baseline value for the next study remains at 10,000 amps because no study was performed. However, during the next Fault current comparison, the Fault current has increased to 11,500 (15 percent change); therefore, a Protection System Coordination Study is required, and a new baseline of 11,500 amps would be established.
>
> **Note:** In the first review described above, if the entity decides to perform a Protection System Coordination Study at the 12.5 percent deviation and the results of the study indicate that the settings still meet the setting criteria of the entity, then no settings changes are required and the baseline Fault current(s) would be updated.

As a third option, an entity has the flexibility to apply a combination of the two methodologies. For example, an entity may choose the periodic Protection System review (Option 1) and review its Facilities operated above 300 kV on a six year interval, while choosing to use the Fault current comparison (Option 2) for its Facilities operated below 300 kV.

Attachment A identifies the Protection System functions susceptible to changes in the magnitude of available short-circuit Fault current. These functions utilize AC current in their measurement to initiate tripping of circuit breakers. The numerical identifiers in Attachment A represent general device functions according to *ANSI/IEEE Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*. The device functions listed in Attachment A are to be reviewed provided they require coordination with other Protection Systems. The following scenarios provide some examples for applying Attachment A.

A "51 – AC inverse time overcurrent" relay connected to a CT on the neutral of a generator step-up transformer, referred to as "51N – AC Inverse Time Earth Overcurrent Relay (Neutral CT Method)" in ANSI/IEEE Standard C37.2, would be included in a Protection System Coordination Study. Also applicable, are "51 – AC Inverse time overcurrent" relays connected to CTs on the phases of an autotransformer for through-fault protection. Overcurrent functions used in conjunction with other functions are to be reviewed as well. An example is a definite-time overcurrent function, which is a "50 – Instantaneous overcurrent" function used in conjunction with a "62 – Time-delay" function.

If the functions listed in Attachment A are used in conjunction with other functions, they would be included in a Protection System Coordination Study provided they require coordination with other Protection Systems. An example of this is a time-delayed "21 – Distance" function, which is a "21 – Distance" function with a "62 – Time-delay" function. Another example would be a definite-time overcurrent function, which is a "50 – Instantaneous overcurrent" function with a "62 – Time-delay" function. A "50 – Instantaneous overcurrent" function used for supervising a "21 – Distance" function would not be included in a Protection System Coordination Study as it does not require coordination with other Protection Systems.

Reviewing "21 – Distance" functions is limited to those applied for phase and ground distance where infeed is used in determining the phase or ground distance setting when zero-sequence mutual coupling is used in determining the setting. Where infeed is not used in determining the setting, "21 – Distance" functions would not be included in a Protection System Coordination Study, as the reach is not susceptible to changes in the magnitude of available short-circuit Fault current. Where infeed is used in determining the reach, coordination can be affected by changes in the magnitude of available short-circuit Fault current. Two examples where infeed may be used in determining the reach, are protection for a transmission line with a long tap and a three-terminal transmission line. Ground distance functions are influenced by zero-sequence mutual coupling. The ground distance measurement can appear to be greater than or less than the true distance to a Fault when there is zero-sequence mutual coupling. The influence of zero-sequence mutual coupling changes with the magnitude of available short-circuit current. Therefore, "21 – Distance" functions would be included in a Protection System Coordination Study, when zero-sequence mutual coupling is used in determining the setting.

Requirement R3

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1~~. Implementing~~ to develop new and revised Protection System settings for BES Elements.

The reliability objective of this requirement is for applicable entities to utilize the process established in Requirement R1. Utilizing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, ~~minimizes~~decreases the possibility of introducing errors, and ~~maximizes~~increases the likelihood of maintaining a coordinated Protection System.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes ~~was~~will be moved to this section.

~~A. Introduction~~

1. ~~**Title:** **System Protection Coordination**~~
2. ~~**Number:** PRC-001-1.1(ii)~~
3. ~~**Purpose:**~~

   ~~To ensure system protection is coordinated among operating entities.~~

4. ~~**Applicability**~~

   ~~**4.1.** Balancing Authorities~~

   ~~**4.2.** Transmission Operators~~

   ~~**4.3.** Generator Operators~~

5. ~~**Effective Date:**~~

   ~~See the Implementation Plan for PRC-001-1.1(ii).~~

ORANGE TEXT – Retirements of R1, R2, R5, and R6 occurring under Project 2007-06.2.

RED TEXT – Retirements of R3 and R4 occurring under Project 2007-06.

~~B. Requirements~~

~~**R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.~~

~~**R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:~~

~~**R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.~~

~~**R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.~~

~~**R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.~~

~~**R3.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.~~

- ~~Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.~~

~~**R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.~~

~~**R4.** Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.~~

~~**R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:~~

~~**R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.~~

~~**R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.~~

~~**R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.~~

~~C. Measures~~

~~**M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.~~

~~**M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)~~

~~**M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)~~

~~D. Compliance~~

~~**1. Compliance Monitoring Process**~~

~~**1.1. Compliance Monitoring Responsibility**~~

~~Regional Reliability Organizations shall be responsible for compliance monitoring.~~

~~**1.2. Compliance Monitoring and Reset Time Frame**~~

~~One or more of the following methods will be used to assess compliance:~~

- ~~Self-certification (Conducted annually with submission according to schedule.)~~
- ~~Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)~~
- ~~Periodic Audit (Conducted once every three years according to schedule.)~~
- ~~Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance.~~

~~1.3. Data Retention~~

~~Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.~~

~~Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.~~

~~If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.~~

~~Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,~~

~~The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.~~

~~1.4. Additional Compliance Information~~

~~None.~~

~~2. Levels of Non-Compliance for Generator Operators:~~

~~**2.1. Level 1:** Not applicable.~~

~~**2.2. Level 2**: Not applicable.~~

~~**2.3. Level 3**: Not applicable.~~

~~**2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.~~

~~3. Levels of Non-Compliance for Transmission Operators:~~

~~**3.1. Level 1:** Not applicable.~~

~~**3.2. Level 2**: Not applicable.~~

~~**3.3. Level 3**: Not applicable.~~

~~**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**3.4.1** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.~~

~~**3.4.2** Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.~~

~~**4. Levels of Non-Compliance for Balancing Authorities:**~~

~~**4.1. Level 1:** Not applicable.~~

~~**4.2. Level 2**: Not applicable.~~

~~**4.3. Level 3**: Not applicable.~~

~~**4.4. Level 4:** Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.~~

~~E. Regional Differences~~

~~None identified.~~

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~0~~	~~April 1, 2005~~	~~Effective Date~~	~~New~~
~~0~~	~~August 8, 2005~~	~~Removed “Proposed” from Effective Date~~	~~Errata~~
~~0~~	~~August 25, 2005~~	~~Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0~~	~~Errata~~
~~1~~	~~November 1, 2006~~	~~Adopted by the NERC Board of Trustees~~	~~Revised~~
~~1.1~~	~~April 11, 2012~~	~~Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)~~	~~Errata associated with Project 2007-17~~
~~1.1~~	~~September 9, 2013~~	~~Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.~~	

~~1.1(i)~~	~~November 13, 2014~~	~~Adopted by the NERC Board of Trustees~~	~~Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS~~
~~1.1(ii)~~	~~February 12, 2015~~	~~Adopted by the NERC Board of Trustees~~	~~Standard revised in Project 2014-01:~~ ~~Applicability revised to clarify application of requirements to BES dispersed power producing resources~~
~~2~~	~~May 9, 2012~~	~~Adopted by Board of Trustees~~	~~Deleted Requirements R2, R5, and R6.~~
~~1.1(ii)~~	~~May 29, 2015~~	~~FERC Letter Order in Docket No. RD15-3-000 approving PRC-001-1.1(ii)~~	~~Modifications to adjust the applicability to owners of dispersed generation resources.~~

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Rationale for the Applicability Exclusion in Requirement R3.1~~

~~Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the~~

~~transmission protective systems, as this coordination would not provide reliability benefits to the BES.~~

Implementation Plan

Project 2007-06 System Protection Coordination

Approvals Requested

- PRC-027-1 – Coordination of Protection Systems for Performance During Faults

Retirements Requested

- PRC-001-1.1(ii) – System Protection Coordination[1]

Prerequisite Approvals (for Retirements Requested)

- TOP-009-1 – Knowledge of Composite Protection Systems and Remedial Action Schemes and Their Effects

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 of PRC-027-1)

New or Modified Term(s) for Glossary of Terms Used in NERC Reliability Standards

Protection System Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Effective Date of New or Revised Standards

PRC-027-1 – Coordination of Protection Systems for Performance During Faults

Reliability Standard PRC-027-1 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar

[1] The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of both proposed Reliability Standards PRC-027-1 and TOP-009-1. NERC is proposing the complete retirement of PRC-001-1.1(ii) in the implementation plans associated with both PRC-027-1 and TOP-009-1. The Project 2007-06 System Protection Coordination Mapping Document shows how PRC-027-1 addresses requirements R3 and R4 of PRC-001-1.1(ii). The remaining requirements of PRC-001-1.1(ii) – Requirements R1, R2, R5, and R6 are proposed for retirement in Project 2007-6.2 Phase 2 of System Protection Coordination (see the Mapping Document for Project 2007-06.2 Phase 2 of System Protection Coordination).

quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Effective Date for New or Modified NERC Glossary Terms

The NERC Glossary Term “Protection System Coordination Study” shall become effective on the effective date for PRC-027-1.

Retirements

PRC-001-1.1(ii) – System Protection Coordination

PRC-001-1.1(ii) – System Protection Coordination shall be retired at midnight of the day immediately prior to the day that TOP-009-1 and PRC-027-1 become effective.

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Implementation Plan

Project 2007-06 System Protection Coordination

Approvals Requested

- PRC-027-1 – Coordination of Protection ~~System~~Systems for Performance During Faults
- ~~PRC-001-3 – System Protection Coordination~~

Retirements Requested

- PRC-001-1.1(ii) – System Protection Coordination[1]

Prerequisite Approvals (for Retirements Requested)

- ~~N/A~~
- TOP-009-1 – Knowledge of Composite Protection Systems and Remedial Action Schemes and Their Effects

Applicable Entities

~~Standard~~	~~Applicable Entities~~					
	~~TO~~	~~GO~~	~~DP~~	~~TOP~~	~~GOP~~	~~BA~~
~~PRC-027-1: Coordination of Protection System Performance During Faults~~	~~X~~	~~X~~	~~X~~			
~~PRC-001-3: System Protection Coordination~~				~~X~~	~~X~~	~~X~~

- Transmission Owner
- Generator Owner
- Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 of PRC-027-1)

New or Modified Term(s) for Glossary of Terms Used in NERC Reliability Standards

- ~~None~~

[1] The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of both proposed Reliability Standards PRC-027-1 and TOP-009-1. NERC is proposing the complete retirement of PRC-001-1.1(ii) in the implementation plans associated with both PRC-027-1 and TOP-009-1. The Project 2007-06 System Protection Coordination Mapping Document shows how PRC-027-1 addresses requirements R3 and R4 of PRC-001-1.1(ii). The remaining requirements of PRC-001-1.1(ii) – Requirements R1, R2, R5, and R6 are proposed for retirement in Project 2007-6.2 Phase 2 of System Protection Coordination (see the Mapping Document for Project 2007-06.2 Phase 2 of System Protection Coordination).

Protection System Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Effective Date of New or Revised Standards

PRC-027-1 – Coordination of Protection ~~System~~Systems for Performance During Faults

Reliability Standard PRC-027-1 shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

~~PRC-001-3 – System~~ Effective Date for New or Modified NERC Glossary Terms

The NERC Glossary Term "Protection System Coordination

~~PRC-001-3~~ Study" shall become effective on the ~~first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become~~ effective ~~on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction~~date for PRC-027-1.

~~Retirement~~

Retirements

PRC-001-1.1(ii) – System Protection Coordination

PRC-001-1.1(ii) – System Protection Coordination shall be retired at midnight of the day immediately prior to the ~~first day of the first calendar quarter that is twelve (12) months after the date that the PRC-001-3 is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, PRC-001-1.1(ii) shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter that is twelve (12) months after the date that the PRC-001-3 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction~~day that TOP-009-1 and PRC-027-1 become effective.

Unofficial Comment Form

Project 2007-06 System Protection Coordination
PRC-027-1 (Draft 6)

DO NOT use this form for submitting comments. Use the electronic form to submit comments on draft 6 of **PRC-027-1 – Coordination of Protection Systems for Performance During Faults**. The electronic form must be submitted by **8:00 p.m. Eastern, Friday, September 11, 2015.**

Documents and information about this project are available on the project page. If you have questions, contact Standards Developer, Al McMeekin, (via email) or at (404) 446-9675.

Background Information

Project 2007-06 System Protection Coordination originated in 2007 to address directives from FERC Order 693 and other issues identified by the System Protection and Control Task Force pertaining to PRC-001. The System Protection Coordination Standard Drafting Team (SPCSDT) developed Reliability Standard PRC-027-1 with the stated purpose: "*To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.*" PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii).

In conjunction with Project 2007-06.2 Phase 2 of System Protection Coordination, NERC is proposing the complete retirement of PRC-001-1.1(ii). In Phase 2, Requirement R1 is being incorporated into the proposed Reliability Standard TOP-009-1. Requirements R2, R5, and R6 are proposed for retirement as the reliability objectives of those requirements are addressed by other TOP/IRO standards pending regulatory approval. The Mapping Document on that project page explains how the reliability objectives of Requirements R1, R2, R5, and R6 are addressed. The remaining two Requirements R3 and R4 of PRC-001-1.1(ii) are addressed by PRC-027-1 as shown in the Project 2007-06 System Protection Coordination Mapping Document. The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of Reliability Standards PRC-027-1 and TOP-009-1 (as proposed by Project 2007-06.2 Phase 2 of System Protection Coordination). NERC is proposing the retirement of PRC-001-1.1(ii) in the implementation plans associated with both projects. See the Phase 2 project page for more details. Collaboratively, these two projects are proposing the retirement of PRC-001-1.1(ii).

Draft 5 of PRC-027-1 was posted for formal comment and ballot from April 1 – May 15, 2015. The standard received affirmative votes totaling 39.63 percent. The drafting team appreciated the feedback industry stakeholders provided and incorporated many of the suggested revisions into draft 6 of the standard. In accordance with section **4.13: Additional Ballots** of the Standards Process Manual, the drafting team is not providing written responses to the comments with this posting because significant revisions to the standard were made and an Additional Ballot will be conducted. Based on stakeholder comments, the drafting team modified the proposed standard as follows:

Defined term

Protection System Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Purpose

Changed from: "To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults" to "To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults."

Applicability

Changed the Facilities language to be consistent with the revised "Purpose" of the standard. It now reads: "Protection Systems installed to detect and isolate Faults on BES Elements."

Requirements

Requirement R1

Revised the language in the core requirement to: "Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults."

Part 1.1

Revised the language from: "A method to review and update the information required to develop new or revised Protection System settings." to "A review and update of short-circuit models for the BES Elements under study."

Part 1.2

Deleted "A review of Protection System settings affected by System changes."

Part 1.3

Removed from Requirement R1. Revised and incorporated into new Requirement R2.

Part 1.4

Removed the descriptor "quality" and the phrase "prior to implementation." Part 1.4 is the new Part 1.2 and reads as follows: "A review of the developed Protection System settings."

Part 1.5

The language of Part 1.5 was revised for clarity and is the new Part 1.3.

Requirement R2
Revised the language from the previous Requirement R1, Part 1.3 and made it new Requirement R2. Removed the term “existing entity-designated” and the associated footnote. New Requirement R2 now references “Attachment A” which lists Protection System functions that are applicable to the standard, if the entity uses available Fault current levels to develop Protection System settings. These are the only functions that require study to determine that coordination is maintained for those Protection System functions for each BES Element.

The language in Requirement R2, Option 2 was clarified to explain that the six-year interval is inclusive of the Fault current comparisons and any resulting Protection System Coordination Study(ies). Option 2 now includes a footnote pertaining to the development of an initial Fault current baseline as well as updating or creating baselines after the effective date of the standard. The footnote states: “The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline by performing a Protection System Coordination Study.”

Requirement R3
The previous Requirement R2 is now Requirement R3.

Measures
Revisions commensurate with changes made to the requirements.

VSLs
Revisions commensurate with changes made to the requirements.

Description
Draft 6 of PRC-027-1 consists of three proposed requirements.

Requirement R1 mandates that entities establish a process for developing new and revised Protection System settings for BES Elements to operate in the intended sequence during Faults, and stipulates certain attributes that must be included in the process. Because Protection System designs and philosophies of entities vary, entities are provided latitude in developing their coordination processes.

Requirement R2 mandates that entities periodically perform Protection System Coordination Studies and/or compare existing Fault current values to established Fault current baselines for Protection Systems applied on BES Elements that are identified as being affected by changes in Fault current. The applicable Protection System functions are identified in Attachment A. These periodic reviews increase the likelihood that incremental changes to the BES that impact coordination are revealed. Requirement R2 provides responsible entities (Distribution Providers, Generator Owners, and Transmission Owners) with options to assess the state of their Protection System coordination.

Requirement R3 mandates that entities utilize its process established in accordance with Requirement R1. Implementing each of the elements of the process facilitates a consistent approach in the development of accurate Protection System settings, by minimizing the introduction of errors, thereby maximizing the likelihood of maintaining a coordinated Protection System.

The Project 2007-06 System Protection Coordination Standard Drafting Team (SPCSDT) is posting draft 6 of Reliability Standard PRC-027-1 “Protection System Coordination for Performance During Faults” for comment from July 29, 2015 to September 11, 2015.

Questions

1. The term “entity-designated” and its associated footnote were removed and replaced by “Attachment A.” Attachment A lists the Protection System functions applicable in the standard. Do you agree that Attachment A includes the Protection System functions that must be reviewed to maintain Protection System coordination when Fault current levels change? If not, please provide the basis for your disagreement and any proposed revisions.

   ☐ Yes
   ☐ No
   Comments:

2. Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.

   ☐ Yes
   ☐ No
   Comments:

3. If you have any other comments that you haven’t already provided in response to the above questions, please provide them here.

   Comments:

Mapping of Requirements from PRC-001-1.1(ii) to PRC-027-1

Project 2007-06 System Protection Coordination

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.	Being proposed to be moved to a new TOP Reliability Standard by Project 2007-06.2 Phase 2: System Protection Coordination	N/A
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	Being proposed for retirement by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. • Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition. R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	PRC-027-1: Requirements R1 and R2 Note: Applicability changed to GO, TO and DP	R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: 1.1 A review and update of short-circuit models for the BES Elements under study. 1.2 A review of the developed Protection System settings. 1.3 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to: 1.3.1 Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities. 1.3.2 Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified. 1.3.3 Verify that identified coordination issue(s) associated with the proposed Protection System settings for the

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		associated BES Elements are addressed prior to implementation. 1.3.4 Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during: 1.3.4.1. Implementation or commissioning. 1.3.4.2. Misoperation investigations. 1.3.4.3. Maintenance activities. 1.3.4.4. Emergency replacements made due to failures of Protection System components. R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A: • Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or • Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years; or • Option 3: A combination of the above. R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.
R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	PRC-027-1: Requirements R1 and R2 Note: Applicability changed to GO, TO and DP	R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: 1.1 A review and update of short-circuit models for the BES Elements under study. 1.2 A review of the developed Protection System settings. 1.3 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to: 1.3.1 Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		1.3.2 Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified. 1.3.3 Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation. 1.3.4 Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during: 1.3.4.1. Implementation or commissioning. 1.3.4.2. Misoperation investigations. 1.3.4.3. Maintenance activities. 1.3.4.4. Emergency replacements made due to failures of Protection System components. R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		with Protection System functions identified in Attachment A: • Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or • Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years; or • Option 3: A combination of the above. R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.
R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others: R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could	Being proposed for retirement by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
require changes in the Transmission Operator's Protection Systems. R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.		
R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Being proposed for retirement by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Mapping of Requirements from PRC-001-1.1(ii) to PRC-027-1

Project 2007-06 System Protection Coordination

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.	Being ~~addressed~~proposed to be moved to a new TOP Reliability Standard by Project 2007-06.2 Phase 2: System Protection Coordination	N/A
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	Being ~~addressed~~proposed for retirement by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. • Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition. R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	PRC-027-1: Requirements R1 and R2 Note: Applicability changed to GO, TO and DP	R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process ~~to develop~~for developing new and revised Protection System settings for ~~its~~ BES Elements, such that the Protection Systems ~~to~~ operate in the intended sequence during Faults. The process shall include: ~~1.1.~~ 1.1 A ~~method to~~ review and update ~~the information required to develop new or revised Protection System settings.~~ ~~A review~~ of ~~Protection System settings affected by System changes.~~short-circuit models for the BES Elements under study. 1.~~3.~~2 A review of ~~existing entity-designated~~the developed Protection System settings ~~based on one of the following:~~. • ~~**Periodic Fault current studies:** A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at the bus under study, and evaluated in a time interval not to exceed six calendar years, or~~ • ~~**Periodic review of Protection System settings:** A time interval, not to exceed six calendar years, or~~ • ~~A combination of the above.~~

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		~~1.4. A quality review of the Protection System settings prior to implementation.~~ ~~1.5.~~1.3 For ~~new or revised~~ Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities~~,~~ (Transmission Owners, Generator Owners, and Distribution Providers), ~~procedures~~provisions to: 1.~~5~~3.1~~.~~ ~~Communicate~~ Provide the proposed Protection System settings ~~with the other functional entities~~to the owner(s) of the electrically-joined Facilities. 1.~~5~~3.2~~.~~ ~~Review~~Respond to any owner(s) that provided its proposed Protection System settings ~~provided by other functional entities, and respond regarding the proposed settings. The response should identify~~pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or ~~affirm~~affirming that no coordination issue(s) were identified. 1.~~5.~~3.3 Verify that ~~any~~ identified coordination issue(s) associated with the proposed Protection System settings for

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		the associated BES Elements are addressed prior to implementation. 1.3.4 Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during: 1.3.4.1. Implementation or commissioning. 1.3.4.2. Misoperation investigations. 1.3.4.3. Maintenance activities. 1.3.4.4. Emergency replacements made due to failures of Protection System components. R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall ~~implement the~~, for each BES Element with Protection System functions identified in Attachment A: • Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or • Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years; or • Option 3: A combination of the above. R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in ~~accordance with~~ Requirement R1 to develop new and revised Protection System settings for BES Elements.
R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	PRC-027-1: Requirements R1 and R2 Note: Applicability changed to GO, TO and DP	R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process ~~to develop~~for developing new and revised Protection System settings for ~~its~~ BES Elements, such that the Protection Systems ~~to~~ operate in the intended sequence during Faults. The process shall include: ~~1.1.~~ 1.1 A ~~method to~~ review and update ~~the information required to develop new or revised Protection System settings.~~ ~~A review~~ of ~~Protection System settings affected by System changes.~~short-circuit models for the BES Elements under study. 1.~~3.~~2 A review of ~~existing entity-designated~~the developed Protection System settings ~~based on one of the following:~~. ~~• **Periodic Fault current studies:** A 15 percent or greater deviation in Fault current (either three-phase or phase-to-~~

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		~~ground) from an established Fault current baseline for Protection Systems at the bus under study, and evaluated in a time interval not to exceed six calendar years, or~~ • ~~**Periodic review of Protection System settings:** A time interval, not to exceed six calendar years, or~~ • ~~A combination of the above.~~ ~~1.4. A quality review of the Protection System settings prior to implementation.~~ ~~1.5.~~1.3 For ~~new or revised~~ Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), ~~procedures~~provisions to: 1.~~5~~3.1. ~~Communicate~~ Provide the proposed Protection System settings ~~with the other functional entities~~to the owner(s) of the electrically-joined Facilities. 1.~~5~~3.2. ~~Review~~Respond to any owner(s) that provided its proposed Protection System settings ~~provided by other functional entities, and respond regarding the proposed settings. The~~

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		~~response should identify~~pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or ~~affirm~~affirming that no coordination issue(s) were identified. 1.~~5.~~3.3 Verify that ~~any~~ identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation. 1.3.4 Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during: 1.3.4.1. Implementation or commissioning. 1.3.4.2. Misoperation investigations. 1.3.4.3. Maintenance activities. 1.3.4.4. Emergency replacements made due to failures of Protection System components. R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall ~~implement the~~, for each BES Element with Protection System functions identified in Attachment A:

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
		• Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or • Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years; or • Option 3: A combination of the above. R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in ~~accordance with~~ Requirement R1 to develop new and revised Protection System settings for BES Elements.
R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others: R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.	Being ~~addressed~~proposed for retirement by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

Requirement in BOT-Adopted PRC-001-1.1(ii)	Action Taken	Requirement or Language in Proposed PRC-027-1
R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.		
R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Being ~~addressed~~proposed for retirement by Project 2007-06.2 Phase 2: System Protection Coordination	N/A

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Violation Risk Factor and Violation Severity Level Justification Document

Project 2007-06 System Protection Coordination

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in Federal Energy Regulatory Commission (FERC) approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System (BPS). In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange

- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A VRF of Medium is appropriate for this requirement because failure by an entity to establish a process to develop settings for its Bulk Electric System (BES) Protection Systems to operate in the intended sequence during Faults could directly affect the electrical state or the capability of the BES. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems. However, a violation of this requirement is unlikely to lead to BES instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) system modeling and data exchange. Requirement R1 mandates that entities establish a process to address all aspects of BES Protection System coordination, including the updating of modeling information and the exchange of Protection System data with other owners, when applicable.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The requirement utilizes Parts to specify items that must be addressed within the settings development process. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-2, Requirements R1 and R2, which are related to developing and documenting a Protection System Maintenance Program and have VRFs of Medium.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A VRF of Medium is appropriate for this requirement because failure by an entity to establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could directly affect the electrical state or the capability of the BPS. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems. However, a violation of this requirement is unlikely to lead to BES instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 or Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.3. OR The responsible entity failed to establish any process in accordance with Requirement R1.

VSL Justifications for PRC-027-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no "consequence of lowering the current level of compliance."
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the High and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSLs use language similar to that used in the associated requirement and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSLs are based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-027-1, Requirement R2	
VRF for Requirement R2 is Medium	
NERC VRF Discussion	A VRF of Medium is appropriate for this requirement because failure to periodically perform a Protection System Coordination Study for existing Protection Systems could lead to failure in identifying and addressing changes in Fault current that have accumulated over time. These deviations in Fault current could result in miscoordinated Protection Systems which could, under anticipated Emergency, abnormal, or restorative conditions, directly and adversely affect the electrical state or the capability of the BES or the ability to effectively monitor and control the BES. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems. However, a violation of this requirement is unlikely to lead to BES instability, separation, or cascading failures.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BES. Requirement R2 relates to one of these areas; specifically, protection systems and their coordination. Requirement R2 mandates that entities periodically perform Protection System Coordination Studies or Fault current comparisons to verify Protection Systems remain coordinated.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-1, Requirement R3, which relates to periodically performing comprehensive assessments to evaluate the effectiveness of UVLS Programs.

VRF Justifications for PRC-027-1, Requirement R2	
VRF for Requirement R2 is Medium	
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A VRF of Medium is appropriate for this requirement because failure to periodically perform a Protection System Coordination Study for existing Protection Systems could lead to failure in identifying and addressing changes in Fault current that have accumulated over time. These deviations in Fault current could result in miscoordinated Protection Systems which could, under anticipated Emergency, abnormal, or restorative conditions, directly and adversely affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems. However, a violation of this requirement is unlikely to lead to BES instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3 but was late by less than or equal to 30 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 90 calendar days. OR The responsible entity failed to perform Option 1, Option 2, or Option 3, in accordance with Requirement R2.

VSL Justifications for PRC-027-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no "consequence of lowering the current level of compliance."

the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the proposed VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSLs use language similar to that used in the associated requirement and is, therefore, consistent with the requirement.
FERC VSL G4	The VSLs are based upon a single violation, not a cumulative number of violations.

Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF Justifications for PRC-027-1, Requirement R3	
VRF for Requirement R3 is High	
NERC VRF Discussion	A VRF of High is appropriate for this requirement because failure by an entity to utilize its process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could place the BES at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS. Requirement R2 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) system modeling and data exchange. Requirement R3 mandates that entities utilize their process established in Requirement R1 that incorporates all actions necessary to to develop settings for its BES Protection Systems to operate in the intended sequence during Faults.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.

VRF Justifications for PRC-027-1, Requirement R3	
VRF for Requirement R3 is High	
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-2, Requirements R3 and R4, which are related to implementing time-based and performance-based maintenance program(s) respectively for Protection Systems.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A VRF of High is appropriate for this requirement because failure by an entity to utilize its process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could place the BES at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to utilize the process established in accordance with Requirement R1.

VSL Justifications for PRC-027-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no "consequence of lowering the current level of compliance."
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses language similar to that used in the associated requirement and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

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This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-027-1. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in ~~FERC~~ Federal Energy Regulatory Commission (FERC) approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System~~.~~ (BPS). In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the ~~Bulk-Power System~~BPS:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange

- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. -Each requirement must have at least one VSL.- While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance
Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A ~~medium~~ VRF of Medium is appropriate for this requirement because ~~an entity's~~ failure by an entity to establish a process to develop settings for its Bulk Electric System (BES) Protection Systems to operate in the intended sequence during Faults could directly affect the electrical state or the capability of the ~~Bulk-Power System.~~ BES. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems. However, a violation of this requirement is unlikely to lead to ~~Bulk-Power System~~BES instability, separation, or cascading failures~~. A medium VRF assignment is appropriate given the level of risk to System performance resulting from the lack of coordinated Protection Systems. For these reasons, the requirement meets the NERC criteria for~~, or to hinder restoration to a ~~Medium VRF~~normal condition.

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the ~~Bulk-Power System.~~BPS. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) system modeling and data exchange. Requirement R1 mandates that entities establish a process to address all aspects of BES Protection System coordination, including the updating of modeling information and the exchange of Protection System data with other owners, when applicable ~~(see, Requirement R1, Parts 1.1 and 1.5).~~.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	~~Because Parts (previously called sub-Requirements) are no longer assigned individual VRFs, this Guideline is no longer applicable.~~This requirement does not use sub-requirements so only one VRF was assigned. The requirement utilizes Parts to specify items that must be addressed within the settings development process. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-2, Requirements R1 and R2, which are related to developing and documenting a Protection System Maintenance Program and have VRFs of Medium.

VRF Justifications for PRC-027-1, Requirement R1	
VRF for Requirement R1 is Medium	
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A ~~medium~~ VRF of Medium is appropriate for this requirement because ~~an entity's~~ failure by an entity to establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could directly affect the electrical state or the capability of the ~~Bulk-Power System.~~ BPS. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems. However, a violation of this requirement is unlikely to lead to ~~Bulk-Power System~~BES instability, separation, or cascading failures~~. A medium VRF assignment is appropriate given the level of risk to System performance resulting from the lack of coordinated Protection Systems. For these reasons, the requirement meets the NERC criteria for~~, or to hinder restoration to a ~~Medium VRF~~normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	~~N/A~~The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 or Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include ~~one~~Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include ~~two or more Parts~~Requirement R1, Part 1.3. OR The responsible entity failed to establish ~~a~~any process in accordance with Requirement R1.

VSL Justifications for PRC-027-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no "consequence of lowering the current level of compliance."
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the High and Severe ~~and High~~ VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The ~~VSL uses similar~~ VSLs use language similar to that used in the associated requirement and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The ~~VSL is~~VSLs are based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-027-1, Requirement R2	
VRF for Requirement R2 is ~~High~~Medium	
NERC VRF Discussion	A ~~high~~ VRF of Medium is appropriate for ~~Requirement R2~~ this requirement because failure to ~~implement the process established in Requirement R1~~periodically perform a Protection System Coordination Study for existing Protection Systems could~~, “~~ lead to failure in identifying and addressing changes in Fault current that have accumulated over time. These deviations in Fault current could result in miscoordinated Protection Systems which could, under ~~emergency~~anticipated Emergency, abnormal, or restorative conditions ~~anticipated by the preparations~~, directly ~~cause~~and adversely affect the electrical state or ~~contribute to bulk electric system~~the capability of the BES or the ability to effectively monitor and control the BES. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems. However, a violation of this requirement is unlikely to lead to BES instability, separation, or ~~a~~ cascading ~~sequence of~~ failures~~, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.” This requirement meets the NERC criteria for a High VRF~~.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the ~~BPS.~~ BES. Requirement R2 relates to ~~two~~one of these areas~~,~~; specifically ~~(i)~~, protection systems and their coordination~~; and (ii) system modeling and data exchange.~~. Requirement R2 mandates that entities ~~implement the process established in Requirement R1 that incorporates all actions necessary~~periodically perform Protection System Coordination Studies or Fault current comparisons to ~~achieve coordination of~~verify Protection Systems remain coordinated.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	~~Because Parts (previously called sub-Requirements) are no longer assigned individual VRFs, this Guideline is no longer applicable.~~This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.

VRF Justifications for PRC-027-1, Requirement R2	
VRF for Requirement R2 is ~~High~~Medium	
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-~~005-2, Requirements~~010-1, Requirement R3~~ and R4~~, which ~~are related~~relates to ~~implementing time-based and performance-based maintenance program(s) respectively for Protection Systems~~periodically performing comprehensive assessments to evaluate the effectiveness of UVLS Programs.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A ~~high~~ VRF of Medium is appropriate for ~~Requirement R2~~ this requirement because failure to ~~implement the process established in Requirement R1~~periodically perform a Protection System Coordination Study for existing Protection Systems could~~, "~~ lead to failure in identifying and addressing changes in Fault current that have accumulated over time. These deviations in Fault current could result in miscoordinated Protection Systems which could, under ~~emergency~~anticipated Emergency, abnormal, or restorative conditions ~~anticipated by the preparations~~, directly ~~cause~~and adversely affect the electrical state or ~~contribute to bulk electric system~~the capability of the BES, or the ability to effectively monitor and control the BES. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems. However, a violation of this requirement is unlikely to lead to BES instability, separation, or ~~a~~ cascading ~~sequence of~~ failures~~, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition." This requirement meets the NERC criteria for a High VRF~~.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
~~N/A~~The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3 but was late by less than or equal to 30 calendar days.	~~N/A~~The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The responsible entity ~~implemented the process established~~performed a Protection System Coordination Study for each BES Element, in accordance with Requirement ~~R1~~R2, Option 1, Option 2, or Option 3, but ~~failed~~was late by more than 60 calendar days but less than or equal to ~~implement one Part~~90 calendar days.	The responsible entity ~~implemented the process established~~performed a Protection System Coordination Study for each BES Element, in accordance with Requirement ~~R1~~R2, Option 1, Option 2, or Option 3, but ~~failed to implement two or~~ was late by more ~~Parts.~~ than 90 calendar days. OR The responsible entity failed to ~~implement the process established~~perform Option 1, Option 2, or Option 3, in accordance with Requirement ~~R1~~R2.

VSL Justifications for PRC-027-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no "consequence of lowering the current level of compliance."
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the ~~Severe and High~~proposed VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The ~~VSL uses similar~~ VSLs use language similar to that used in the associated requirement and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The ~~VSL is~~VSLs are based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-027-1, Requirement R3	
VRF for Requirement R3 is High	
NERC VRF Discussion	A VRF of High is appropriate for this requirement because failure by an entity to utilize its process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could place the BES at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS. Requirement R2 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) system modeling and data exchange. Requirement R3 mandates that entities utilize their process established in Requirement R1 that incorporates all actions

VRF Justifications for PRC-027-1, Requirement R3	
VRF for Requirement R3 is High	
	necessary to to develop settings for its BES Protection Systems to operate in the intended sequence during Faults.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-2, Requirements R3 and R4, which are related to implementing time-based and performance-based maintenance program(s) respectively for Protection Systems.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A VRF of High is appropriate for this requirement because failure by an entity to utilize its process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults could place the BES at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. This VRF emphasizes the risk to the BES that results from miscoordinated Protection Systems.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-027-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity failed to utilize the process established in accordance with Requirement R1.

VSL Justifications for PRC-027-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-001-1.1(ii), Requirements R3 and R4, so there is no "consequence of lowering the current level of compliance."
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-027-1, Requirement R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses language similar to that used in the associated requirement and is, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

Standards Announcement Reminder

Project 2007-06 System Protection Coordination
PRC-027-1

Additional Ballot and Non-binding Poll Open through September 11, 2015

Now Available

An additional ballot for draft six of **PRC-027-1 – Coordination of Protection Systems for Performance During Faults** and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern, Friday, September 11, 2015.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standard and associated VRFs and VSLs by clicking here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at EROhelpdesk@nerc.net (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

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Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Formal Comment Period Open through September 11, 2015

Now Available

A 45-day formal comment period for draft six of **PRC-027-1 – Coordination of Protection Systems for Performance During Faults** is open through **8 p.m. Eastern, Friday, September 11, 2015.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting
Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Next Steps
An additional ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 2-11, 2015.**

Standards Development Process
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For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

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Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Formal Comment Period Open through September 11, 2015

Now Available

A 45-day formal comment period for draft six of **PRC-027-1 – Coordination of Protection Systems for Performance During Faults** is open through **8 p.m. Eastern, Friday, September 11, 2015.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Next Steps

An additional ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 2-11, 2015.**

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

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Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Additional Ballot and Non-binding Poll Results

Now Available

A formal comment period and additional ballot for **Project 2007-06 System Protection Coordination** as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern, Friday, September 11, 2015.**

The additional ballot received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides detailed results for the ballot and non-binding poll.

Ballot	Non-binding Poll
Quorum /Approval	Quorum/Supportive Opinions
84.34% / 69.76%	81.96% / 70.00%

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/25)
Ballot Name: 2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) AB 2 ST
Voting Start Date: 9/2/2015 12:01:00 AM
Voting End Date: 9/11/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 280
Total Ballot Pool: 332
Quorum: 84.34
Weighted Segment Value: 69.77

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	82	1	50	0.735	18	0.265	0	3	11
Segment: 2	8	0.5	4	0.4	1	0.1	0	2	1
Segment: 3	81	1	42	0.636	24	0.364	1	3	11
Segment: 4	29	1	9	0.474	10	0.526	0	1	9
Segment: 5	74	1	33	0.611	21	0.389	0	7	13
Segment: 6	46	1	28	0.718	11	0.282	0	0	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	2	0.2	1	0.1	1	0.1	0	0	0

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Segment: 10	8	0.8	8	0.8	0	0	0	0	0
Totals:	332	6.7	177	4.674	86	2.026	1	16	52

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		Negative	Third-Party Comments
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Negative	Comments Submitted
1	Beaches Energy Services	Don Cuevas		None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy	Terry Harbour		Affirmative	N/A

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	Co.				
1	Black Hills Corporation	Wes Wingen		Abstain	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Third-Party Comments
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis	marcus lotto	None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy	William Smith		Negative	Comments Submitted

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	Corporation				
1	Georgia Transmission Corporation	Jason Snodgrass	Greg Davis	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	Iberdrola - Central Maine Power Company	Joe Turano		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Meghan Ferguson	Affirmative	N/A
1	JEA	Ted Hobson	Thomas McElhinney	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Doug Bantam		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A

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1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Alan MacNaughton		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Affirmative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources -	Laurie Williams		Affirmative	N/A

	Public Service Company of New Mexico				
1	Portland General Electric Co.	John Walker		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		Negative	Third-Party Comments
1	SaskPower	Wayne Guttormson		None	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southern Illinois Power Cooperative	William Hutchison		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee,	Scott Langston		Abstain	N/A

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	FL)				
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Negative	Comments Submitted
2	California ISO	Richard Vine		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	christina bigelow	Elizabeth Axson	Affirmative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula	Mark Wilson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Third-Party Comments
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A

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3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
3	BC Hydro and Power Authority	Pat Harrington		Negative	Comments Submitted
3	Beaches Energy Services	Steven Lancaster		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Bartow, Florida	Matt Culverhouse		Negative	Comments Submitted
3	City of Garland	Ronnie Hoeinghaus		None	N/A
3	City of Green Cove Springs	Mark Schultz		None	N/A
3	City of Leesburg	Chris Adkins		Negative	Third-Party Comments
3	City of Redding	Bill Hughes	Mary Downey	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Negative	Third-Party Comments
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Charles Morgan		Negative	No Comment Submitted

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3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	CPS Energy	Brian Bartos		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Cindy Stewart	Richard Hoag	None	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker		Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Mace Hunter		Negative	Third-Party Comments
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A

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3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		None	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Northeast Utilities	Mark Kenny		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	PHI - Potomac	Mark Yerger		Affirmative	N/A

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	Electric Power Co.				
3	Platte River Power Authority	Jeff Landis		None	N/A
3	PNM Resources	Michael Mertz		Affirmative	N/A
3	Portland General Electric Co.	Thomas Ward		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	Comments Submitted
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		Abstain	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Third-Party Comments
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Negative	Comments Submitted

3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-County Electric Cooperative, Inc.	Chris Giles		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	We Energies - Wisconsin Electric Power Marketing	Jim Keller		Negative	Comments Submitted
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Negative	Third-Party Comments
4	Austin Energy	Tina Garvey		None	N/A
4	City of Clewiston	Lynne Mila		None	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		None	N/A
4	City of Redding	Nick Zettel	Mary Downey	Affirmative	N/A
4	City of Winter Park	Mark Brown		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Negative	Comments Submitted
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	Comments Submitted

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4	Flathead Electric Cooperative	Russ Schneider		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		None	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Negative	Third-Party Comments
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	None	N/A
4	Keys Energy Services	Stanley Rzad		Negative	Third-Party Comments
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A

4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative	Comments Submitted
4	Utility Services, Inc.	Brian Evans-Mongeon	brian robinson	Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Anthony Jankowski	Matthew Beilfuss	None	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Affirmative	N/A
5	Austin Energy	Jeanie Doty		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
5	BC Hydro and Power Authority	Clement Ma		Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Third-Party Comments
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Abstain	N/A
5	City and County of San Francisco	Daniel Mason		Abstain	N/A
5	City of Garland	Minh Ngo		None	N/A
5	City of	Jim Nail		Affirmative	N/A

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	Independence, Power and Light Department				
5	City of Redding	Paul Cummings	Mary Downey	Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Essential Power, LLC	Gerry Adamski		Affirmative	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	David Schumann		None	N/A

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5	Golden Spread Electric Cooperative, Inc.	Chip Koloini	Sara Bednar	None	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne	manon paquet	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Negative	Comments Submitted
5	North Carolina	Robert Beadle	Scott Brame	Affirmative	N/A

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	Electric Membership Corporation				
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Oxy - Ingleside Cogeneration LP	Michelle D'Antuono		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Barbara Croas		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		None	N/A
5	Seattle City Light	Mike Haynes		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Negative	Comments Submitted

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5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Negative	Comments Submitted
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Negative	Comments Submitted
5	Z_NA	Replacementvoter-Dan Wilson		Affirmative	N/A
6	ACES Power Marketing	Ben Engelby		None	N/A
6	AEP - AEP Marketing	Edward P Cox		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Mary Downey	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A

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6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery		None	N/A
6	Florida Municipal Power Pool	Tom Reedy		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges		Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik	Simon Tanapat	None	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted

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6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
6	Omaha Public Power District	Mark Trumble		None	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Shawn Davis		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham	Chris Janick	Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Negative	Third-Party Comments
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A

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6	Westar Energy	Tiffany Lake		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Negative	Third-Party Comments
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Joe Spencer		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 332 of 332 entries

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/25)
Ballot Name: 2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) Non-Binding Poll AB 2 NB
Voting Start Date: 9/2/2015 12:01:00 AM
Voting End Date: 9/11/2015 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 259
Total Ballot Pool: 315
Quorum: 82.22
Weighted Segment Value: 70

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	77	1	39	0.796	10	0.204	0	16	12
Segment: 2	8	0.4	3	0.3	1	0.1	0	3	1
Segment: 3	77	1	36	0.655	19	0.345	0	11	11
Segment: 4	27	1	7	0.538	6	0.462	0	4	10
Segment: 5	70	1	25	0.625	15	0.375	0	16	14
Segment: 6	44	1	20	0.714	8	0.286	0	8	8
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	2	0.2	1	0.1	1	0.1	0	0	0

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Segment: 10	8	0.7	7	0.7	0	0	0	1	0
Totals:	315	6.5	140	4.628	60	1.872	0	59	56

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A

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1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	Comments Submitted
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis	marcus lotto	None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Negative	Comments Submitted
1	Georgia Transmission Corporation	Jason Snodgrass	Greg Davis	Affirmative	N/A
1	Great Plains Energy - Kansas City Power	James McBee	Douglas Webb	Affirmative	N/A

	and Light Co.				
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Meghan Ferguson	Affirmative	N/A
1	JEA	Ted Hobson	Thomas McElhinney	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Doug Bantam		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A

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1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Affirmative	N/A
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	John Walker		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A

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1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southern Illinois Power Cooperative	William Hutchison		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A

2	California ISO	Richard Vine		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	christina bigelow	Elizabeth Axson	Affirmative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula	Mark Wilson	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
3	BC Hydro and Power Authority	Pat Harrington		Abstain	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		None	N/A
3	Central Electric	Adam Weber		Affirmative	N/A

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	Power Cooperative (Missouri)				
3	City of Bartow, Florida	Matt Culverhouse		Negative	Comments Submitted
3	City of Green Cove Springs	Mark Schultz		None	N/A
3	City of Leesburg	Chris Adkins		Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Charles Morgan		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	CPS Energy	Brian Bartos		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Cindy Stewart	Richard Hoag	None	N/A
3	Florida Municipal	Joe McKinney		Affirmative	N/A

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	Power Agency				
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker		Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Mace Hunter		Negative	Comments Submitted
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		None	N/A

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3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Northeast Utilities	Mark Kenny		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		Negative	Comments Submitted
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		None	N/A
3	PNM Resources	Michael Mertz		Affirmative	N/A
3	Portland General Electric Co.	Thomas Ward		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		Abstain	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Santee Cooper	James Poston		Negative	Comments

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					Submitted
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Negative	Comments Submitted
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-County Electric Cooperative, Inc.	Chris Giles		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Negative	Comments Submitted
4	Austin Energy	Tina Garvey		None	N/A
4	City of Clewiston	Lynne Mila		None	N/A

4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		None	N/A
4	City of Winter Park	Mark Brown		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Negative	Comments Submitted
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	Comments Submitted
4	Flathead Electric Cooperative	Russ Schneider		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		None	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	None	N/A
4	Keys Energy Services	Stanley Rzad		Negative	Comments Submitted
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish	John Martinsen		Affirmative	N/A

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	County				
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative	Comments Submitted
4	Utility Services, Inc.	Brian Evans-Mongeon	brian robinson	Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski	Matthew Beilfuss	None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Affirmative	N/A
5	Austin Energy	Jeanie Doty		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
5	BC Hydro and Power Authority	Clement Ma		Abstain	N/A
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Comments Submitted
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted

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5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Abstain	N/A
5	City of Garland	Minh Ngo		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A

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5	Essential Power, LLC	Gerry Adamski		Abstain	N/A
5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	David Schumann		None	N/A
5	Golden Spread Electric Cooperative, Inc.	Chip Koloini	Sara Bednar	None	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne	manon paquet	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Negative	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Abstain	N/A

5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
5	Oxy - Ingleside Cogeneration LP	Michelle D'Antuono		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	Portland General Electric Co.	Barbara Croas		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		None	N/A
5	Seattle City Light	Mike Haynes		Negative	Comments Submitted

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5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Abstain	N/A
5	Tennessee Valley Authority	Brandy Spraker		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		None	N/A
6	ACES Power Marketing	Ben Engelby		None	N/A
6	AEP - AEP Marketing	Edward P Cox		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Basin Electric Power Cooperative	Paul Huettl		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison	Robert Winston		Affirmative	N/A

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	Co. of New York				
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery		None	N/A
6	Florida Municipal Power Pool	Tom Reedy		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges		Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik	Simon Tanapat	None	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Oglethorpe Power	Donna Johnson		Affirmative	N/A

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	Corporation				
6	Omaha Public Power District	Mark Trumble		None	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Shawn Davis		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Abstain	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham	Chris Janick	Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Tiffany Lake		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts	Frederick Plett		Affirmative	N/A

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	Attorney General				
9	City of Vero Beach	Ginny Beigel		Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Joe Spencer		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Previous 1 Next

Showing 1 to 315 of 315 entries

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Survey Report

Survey Details

Name 2007-06 System Protection Coordination | PRC-027-1 & PRC-001-1.1 (ii)

Description

Start Date 7/29/2015

End Date 9/11/2015

Associated Ballots

2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) Non-Binding Poll AB 2 NB

2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) AB 2 ST

Survey Questions

1. The term "entity-designated" and its associated footnote were removed and replaced by "Attachment A." Attachment A lists the Protection System functions applicable in the standard. Do you agree that Attachment A includes the Protection System functions that must be reviewed to maintain Protection System coordination when Fault current levels change? If not, please provide the basis for your disagreement and any proposed revisions.

Yes

No

2. Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.

3. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Responses By Question

1. The term "entity-designated" and its associated footnote were removed and replaced by "Attachment A." Attachment A lists the Protection System functions applicable in the standard. Do you agree that Attachment A includes the Protection System functions that must be reviewed to maintain Protection System coordination when Fault current levels change? If not, please provide the basis for your disagreement and any proposed revisions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Schwarzrock - Berkshire Hathaway - NV Energy - 5 -

Selected Answer: No

Answer Comment:

- Attachment A does not list bus differential protection as an applicable protection function. Bus protection designed using either overcurrent, percentage differential or high impedance differential protection use a sum of currents to detect a bus fault. In an ideal world an increase in fault current would not affect the differential relays, but there are situations where an increase in fault current can negatively affect the differential relays and affect the coordination between bus differential and line relays.
  - Overcurrent and percentage differential relays are usually applied on busses where fault currents are low enough so that CT saturation does not occur. As fault currents increase, the

chances of CT saturation increase which can cause false bus differential operations for external line faults.

- High impedance differential relay voltage settings are calculated based on the voltage that could be developed across the relay with a completely saturated CT. This voltage setting is calculated using the maximum external fault current. With increased fault currents, the voltage that could develop across the relay for a saturated CT could be higher than the voltage setting of the relay. This can also cause false bus differential operations for external line faults.

Bus differential relays should be added to Attachment A to ensure that proper coordination between bus differential relays and line relays for external faults.

Document Name:

Likes: 0

Dislikes: 0

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Northeast Utilities - 3 -

Selected Answer: Yes

Answer Comment:

We agree with the classification of specific protection system elements that require coordination. In addition, this will aid the compliance enforcement process.

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kayleigh Wilkerson - Lincoln Electric System - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter

John Seelke

Segment

1,3,5,6

Entity

PSEG

Region(s)

NPCC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jay Barnett - Exxon Mobil - 7 -

Selected Answer: Yes

Answer Comment:

While I agree that the functions listed are the ones that should be reviewed if fault current levels change, I disagree with using fault current as a trigger for a review *in all circumstances*. For those functions that do not require fault current or Protection System settings from other entities in order to ensure proper coordination, entities should be able to use equipment changes as a trigger for a coordination review. Equipment changes are already used as a trigger for other Reliability Standards and would allow for entities to have a single trigger for multiple Standards. This would add an additional, more cost effective option, while still ensuring Protection Systems on all BES Elements are coordinated. The SDT should include this as another option under Requirement 2 (see proposed revision below). A fault current trigger would remain for those functions that require fault current or Protection System settings from other entities in order to ensure proper coordination.

Proposed Revision:

R2. Each TO, GO, and DP shall, for each BES Element with Protection System functions identified in Attachment A:

Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or

Option 2: . Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years; or,

Option 3: For functions that do not require Fault current or Protection System settings from other entities to ensure proper coordination, perform a PSCS prior to the implementation of new or modified Protection System settings on associated BES Elements.

Option 4: A combination of the above.

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 1 Tarantino Joe On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1,
Ke

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter	Segment
Chris Scanlon	1
Entity	**Region(s)**
Exelon	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Spencer Tacke - Modesto Irrigation District - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

For the GO function, it would be helpful to include 51V-R and 51V-C as in scope relays in Attachment A. Also for GO, it would be helpful to note that 50/27 or 67 relays/protective functions used in generator inadvertent energization schemes are not in scope for PRC-027. Additionally, it's not clear if the 50 includes overcurrent elements used to supervise distance (21) elements.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: No

Answer Comment:

Revision Requirement 1 allows us to develop a criteria for intended sequence which is good. Our only concern is if our criteria changes, there is no verbiage in the standard that allows for a phased implementation plan. One suggestion could be to give a 6 year cycle to be sure improvements are made will staying compliant to the proposed standard.

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer: No

Answer Comment:

See Comments from ACES

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer: No

Answer Comment:

See Comments from ACES

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer: No

Answer Comment:

In Attachment A, it seems that 67 elements used in communication-aided protection schemes should be applicable. If a communication-aided protecton scheme is needed for coordination with remote backup (e.g., long line adjacent to a short line, perhaps), a check may need to be performed that (for example) overreaching ground overcurrent pickups are still appropriate. Tacoma Power will not object to lowering the compliance risk by leaving these elements out of Attachment A, but Tacoma Power did want to bring this to the drafting team's attention.

In Attachment A, or in the Supplemental Material section, breaker failure fault detectors should be discussed. As with the 67 element, if a breaker failure fault detector is set too high in (for example) a ring bus, remote backup protection could operate instead of the local breaker failure. As with the 67 element, Tacoma Power will not object to lowering the compliance risk by leaving these elements out of Attachment A, but it probably should be at least discussed by the drafting team and documented somewhere to avoid confusion later when/after the standard becomes effective.

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer: No

Answer Comment:

Agree with the elements listed, but I question the wording regarding the 21 elements. It sounds as if an entity simply sets this element by just taking a percent of the Positive Sequence Line impedance, even when infeed or mutuals are present (ground only), then the entity would never need to check these elements. However, if another entity does use these factors in determining settings of these elements, then that entity would be required to periodically check the settings. This seems to give a greater degree of risk for compliance

	failure for the entity that applies a more thorough method of setting these elements while leaving no risk to the entity that uses a simpler, less thorough setting method. Generally believe entities should be required to verify through studies that these elements will only operate for their intended zone of protection whenever infeed or mutuals are present.
Document Name:	
Likes:	0
Dislikes:	0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

David Greene - SERC - 10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Paul Nauert	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
David Greene	SERC staff	SERC	10

Voter Information

Voter

David Greene

Segment

10

Entity

SERC

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter
Colby Bellville

Segment
1,3,5,6

Entity
Duke Energy

Region(s)
FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Jonathan Hayes	Southwest Power Pool Inc	SPP	2
Robert Gray	Board of Public Utilities of Kansas City, Kansas	SPP	3
Michael Jacobs	Camstex	NA - Not Applicable	NA - Not Applicable
stephanie Johnson	Westar Energy, Inc	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

We agree that the addition of Attachment A gives the industry guidance to some of the system functions and their applicable in this process especially, in reference to the calculation of the Fault current when conducting the Protection System Coordination Study (PSCS). Additionally, this helps the industry develop effective procedures that will increase the Reliability of the BES.

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Guidry - Louis Guidry On Behalf of: John Lindsey, Cleco Corporation, 6, 5, 3, 1
Michelle Corley, Cleco Corporation, 6, 5, 3, 1
Robert Hirchak, Cleco Corporation, 6, 5, 3, 1
Stephanie Huffman, Cleco Corporation, 6, 5, 3, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2007-06 PRC-027-1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1

Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Voter Information

Voter

Lee Pedowicz

Segment

10

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer: Yes

Answer Comment:

We agree with the classification of specific Protection System components that require coordination. In addition, this will aid the compliance enforcement process. However, clarification is requested with regard to applicability of distance protection element. Does the standard apply to distance elements used solely for non-communication aided protection schemes (for example transfer trip, carrier systems) or for all distance element applications?

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kenn Backholm - Snohomish County PUD No. 1 - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. agrees with the NPCC on the classification of specific protection systems that would entail protection system coordination. However, Hydro One Networks Inc.. would like to ask for clarification within Attachment 1 whether distance (21) elements within communications aided protection schemes are subject to the requirements of this standard. This is because there were conflicting responses provided by the NERC SDT during the Q&A Session held on August 25th, and by NATF during the monthly meeting call on August 27th.

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer: No

Answer Comment:

Attachment A would be a good list of items that must be reviewed if Fault current levels are expected to always increase, but not for any Fault current level change.

Document Name:	
Likes:	0
Dislikes:	0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer:

Answer Comment: Abstain

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer: No

Answer Comment:

Attachment A would be a good list of items that must be reviewed if Fault current levels are expected to always increase, but not for any Fault current level change.

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer: No

Answer Comment:

Attachment A would be a good list of items that must be reviewed if Fault current levels are expected to always increase, but not for any Fault current level change.

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Information

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Voter Information

Voter

Patricia Robertson

Segment

1

Entity

BC Hydro and Power Authority

Region(s)

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Information

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Voter Information

Voter	Segment
Ben Li	2
Entity	**Region(s)**
Independent Electricity System Operator	NPCC

Selected Answer: Yes

Answer Comment:

Note: CAISO is not a party to the submission of the comments below.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Selected Answer: No

Answer Comment:

See Section 3 below

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter
Ginette Lacasse

Segment
1,3,4,5,6

Entity
Seattle City Light

Region(s)
WECC

Selected Answer: No

Answer Comment: See general comments in #3

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - PRC-027 Project

Group Member Name	Entity	Region	Segments
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Voter Information

Voter

Ben Engelby

Segment

6

Entity

ACES Power Marketing

Region(s)

Selected Answer: Yes

Answer Comment:

1. We agree with the removal of the term “entity-designated” and the addition of Attachment A to provide more clarity.
2. Note #2 in the attachment refers to additional details located in the supplemental information section of the standard. Once the standard is approved by FERC, only the applicability section and the requirements (and attachments that are incorporated by reference) will be enforceable. If the drafting team acknowledges that additional details are

	necessary to fully explain the attachment, then those details should be added at this stage of the development process.
Document Name:	
Likes:	0
Dislikes:	0

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

2. Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

yes

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Schwarzrock - Berkshire Hathaway - NV Energy - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Yes,

SCE&G agrees with the SERC PCS committee comments: "It is our understanding that the 6-year evaluation interval begins on the enforcement date, allowing up to 6 years to complete a full system analysis. However, with this not being explicitly stated in the technical basis or implementation plan, we would recommend including that distinction in some location. "

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Yes

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

AEP does not believe that 12 months is adequate for the Implementation Plan, and recommends that it be increased to 24 months, which we believe is more reasonable. The GO often relies on the TO to provide short-circuit studies, which increases the time necessary to establish the initial baseline.

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment:

The Implementation Plan should be extended to 24 months. As it stands now, entities only have 12 months after regulatory approvals to develop a process, establish Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Northeast Utilities - 3 -

Selected Answer:

Answer Comment:

We strongly believe that 12 months is an inadequate amount of time for an entity to develop a formal documented process, establish a Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review. We recommend that the Implementation Plan should be extended to 24 months.

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer:

Answer Comment:

Regarding Implementation Plan: NIPSCO believes 12 month implementation plan is very challenging and inadequate. NIPSCO recommends 24 months for implementation plan to allow entities sufficient time to establish resources and derive processes.

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

The Technical Basis or Implementation Plan does not include sufficient details describing the 6 year evaluation interval. It is our understanding that this 6 year evaluation interval begins on the enforcement date allowing up to 6 years for the system analysis to be completed but this is not specifically stated so we recommend additional reference details be included to explicitly describe the Implementation times.

Document Name:

Likes: 0

Dislikes:	0

Kayleigh Wilkerson - Lincoln Electric System - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer:

Answer Comment:

-

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Yes

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer:

Answer Comment: Yes

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter

John Seelke

Segment

1,3,5,6

Entity

PSEG

Region(s)

NPCC,RFC

Selected Answer:

Answer Comment:

No. While not “per se” an Implementation Plan issue, R2 is unclear as to when the first Protection System Coordination Study must be performed for Attachment A devices under R2. See additional comments in #3 below.

Document Name:

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

Yes.

1) For R2, if an entity decides to go with option 1, does it mean that the entity is not required to do a Protection System Coordination Study until 6 years from the effective date of the standard?

Document Name:

Likes: 0

Dislikes: 0

Jay Barnett - Exxon Mobil - 7 -

Selected Answer:

Answer Comment:

Agree.

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Salt River Project (SRP) has reviewed the Attachment A and has concerns with verifying a Fault Current baseline as required in R3. As this standard is written, this baseline must be created prior to the effective date of the standard. We strongly believe that 12 months is an inadequate amount of time to develop a formal documented process, establish a Fault Current baseline for thousands of relays, and establish a tracking tool for those Fault Current baseline changes and/or periodic review. We request that there be at least a 24 month implementation plan.

Document Name:

Likes: 1 Tarantino Joe On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1,
Ke

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter	Segment
Chris Scanlon	1
Entity	**Region(s)**
Exelon	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Spencer Tacke - Modesto Irrigation District - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5 -

Selected Answer:

Answer Comment:

More detail is needed regarding the implementation plan dates for each of the requirements. Also, required dates for R2 should address Options 1 and 2 individually.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

No; it would be helpful if the Implementation Plan included information on what is required on the effective date of the standard. There is clarifying text on page 7 of the RSAW that states what is required by the effective date of the standard, this could be included in the Implementation Plan.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment:

We do not agree with the proposed implementation plan. For larger entiites with assets in all regions, a 12-month implementation is a challenge. 24-months would be more appropriate without taking on risk.

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:

Answer Comment:

No, See comments from ACES

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:

Answer Comment:

See Comments from ACES

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer:

Answer Comment:

SMUD Supports Salt River Project comments.

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:

Answer Comment:

There are no possible answers listed on this question to choose from (see attached screenshot), however, ITC Holdings would select 'YES' as an answer to this question.

Document Name: Question2_screenshot.pdf

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment:

It appears that, where Option 2 is selected, only the Fault current baselines need to be established prior to the effective date, not (necessarily) any Protection System Coordination Studies. Is this the drafting team's intention?

Where Option 1 is selected, what is the implementation timeframe?

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment:

yes, but no button.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Yes

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Yes

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Paul Nauert	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
David Greene	SERC staff	SERC	10

Voter Information

Voter	Segment
David Greene	10
Entity	**Region(s)**
SERC	SERC

Selected Answer:

Answer Comment:

It is our understanding that the 6-year evaluation interval begins on the enforcement date, allowing up to 6 years to complete a full system analysis. However, with this not being explicitly stated in the technical basis or implementation plan, we would recommend including that distinction in some location.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter	Segment
Colby Bellville	1,3,5,6
Entity	**Region(s)**
Duke Energy	FRCC,SERC,RFC

Selected Answer:

Answer Comment:

Based on our concerns regarding R1, subpart 1.2, as outlined in question 3, Duke Energy cannot agree to the proposed Implementation Plan. If the standard were to be approved as written, the expectation to review the developed Protection System settings, depending on the level of detail expected for the review, would take a significant amount of time to achieve compliance. For larger entities, with a great deal of applicable relays, additional resources would most definitely be required, and time to acquire and train those resources would be necessary. We do not feel the 12 months is an adequate amount of time to achieve compliance with the standard as written.

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Jonathan Hayes	Southwest Power Pool Inc	SPP	2
Robert Gray	Board of Public Utilities of Kansas City, Kansas	SPP	3
Michael Jacobs	Camstex	NA - Not Applicable	NA - Not Applicable
stephanie Johnson	Westar Energy, Inc	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

We agree with the proposed Implementation Plan. In our opinion, the footnote provides the industry a clear and concise objective pertaining to both projects and their dependence on the success of the proposed retirement of PRC-001-1-1 (ii).

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Guidry - Louis Guidry On Behalf of: John Lindsey, Cleco Corporation, 6, 5, 3, 1
Michelle Corley, Cleco Corporation, 6, 5, 3, 1
Robert Hirchak, Cleco Corporation, 6, 5, 3, 1
Stephanie Huffman, Cleco Corporation, 6, 5, 3, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment: Yes

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2007-06 PRC-027-1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1

Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Voter Information

Voter

Lee Pedowicz

Segment

10

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer:

Answer Comment:

Checked--No

As it stands now, entities will not have adequate time, within 12 months, to develop a process, establish Fault current baselines, and establish a tracking tool for Fault current baseline changes and/or periodic review. We recommend that the Implementation Plan be extended to 24 months.

We recommend the implementation plan include a statement clarifying the start date of the 6 year cycle that is described in Requirement R2. Is it the date the standard is effective, or the date the protection system was last reviewed prior to the effective date?

Document Name:

Likes:	0
Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment: Yes.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment: Texas RE agrees with the proposed Implement Plan.

Document Name:

Likes: 0

Dislikes: 0

Kenn Backholm - Snohomish County PUD No. 1 - 6 -

Selected Answer:

Answer Comment: Public Utility District No. 1 of Snohomish County supports Salt River Project comments.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:

Answer Comment:

Hydro One Networks Inc. does not agree with the Implementation Plan as it is unreasonable to implement a process and establish a fault current baseline within 12 months. Further, the Implementation Plan of 12 months borders on the Long-term Planning horizon in requirement R1 itself. The NERC definition of a Long-term Planning horizon is “a planning horizon of one year or longer”. Therefore, Hydro One Networks Inc. agrees with the NPCC, and recommends that the Implementation Plan be extended from 12 months to 24 months.

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer:

Answer Comment:

Yes

Document Name:

Likes:	0
Dislikes:	0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment: Texas RE agrees with the proposed Implementation Plan.

Document Name:

Likes: 0

Dislikes: 0

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer:

Answer Comment: Abstain

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment: Yes

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment: Yes

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Information

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Voter Information

Voter

Patricia Robertson

Segment

1

Entity

BC Hydro and Power Authority

Region(s)

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Information

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Voter Information

Voter	Segment
Ben Li	2
Entity	**Region(s)**
Independent Electricity System Operator	NPCC

Selected Answer:

Answer Comment:

NO.

The Implementation Plan should be extended to 24 months. As it stands now, entities only have 12 months after regulatory approvals to develop a process, establish Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter

Pamela Hunter

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

SERC

Selected Answer:

Answer Comment:

Yes.

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Selected Answer:

Answer Comment:

SCL does not have issues with this aspect. However, other utilities have expressed a concern about needing more time so it may be worthwhile re-evaluating the scope for implementation plan.

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Yes.

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer:

Answer Comment:

Yes we have no issues but we have heard others are concerned that they will need more time.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

If a utility is in the position to leverage a tool such as CAPE or ASPEN to automate its settings review, then the proposed implementation plan seems feasible. If a utility does not have a software tool in place, then developing and tracking the settings review may require significant resources. This may actually detract from a utility's ability to create and review relay settings.

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - PRC-027 Project

Group Member Name	Entity	Region	Segments
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Voter Information

Voter

Ben Engelby

Segment

6

Entity

ACES Power Marketing

Region(s)

Selected Answer:

Answer Comment:

We agree with the implementation plan that both standards (PRC-027-1 and TOP-009-1) must reach industry consensus before they are presented to the NERC Board for adoption.

Document Name:

Likes:	0
Dislikes:	0

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4 -

Selected Answer:

Answer Comment:

yes

Document Name:

Likes: 0

Dislikes: 0

3. If you have any other comments that you haven’t already provided in response to the above questions, please provide them here.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

none

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Portland General Electric Company (PGE) thanks you for the opportunity to comment on this standard. PGE's System Protection group finds the proposed standard to be generally acceptable. We would, however, request that the drafting team review part 2 of PRC-023-3 Attachment A and consider exclusion of the relay elements listed in 2.1 from the requirement of PRC-027.

Document Name:

Likes: 0

Dislikes: 0

Eric Schwarzrock - Berkshire Hathaway - NV Energy - 5 -

Selected Answer:

Answer Comment:

- Option 2 of R2 is meant to allow an entity to periodically check for a 15 percent of greater deviation in fault current. This option allows the entity to choose an interval of up to six calendar years to perform the fault current comparisons (this comes from the PRC-027-1 supplemental material). Option 2 is worded in a confusing manner so that the intent is not immediately clear without reading the supplemental material.

- Attachment A lists the protection system functions applicable to R2 including: 67 – AC directional overcurrent if used in a **non-communication-aided protection scheme**. This is probably ok if the fault current increases. If the fault current decreases, then any 67 relays used in a communication-aided protection scheme might not work correctly. If the 67 element were set to overreach the other end of the line for a POTT scheme (similar to using a zone 2 element in a POTT scheme) and the fault current decreased, it's possible that the 67 element might now see faults at a maximum distance less than the distance of the line. This would render the POTT scheme not as effective since the element used to trigger the scheme does not see the entire line.

Option 2 states that a protection coordination study should be performed when a 15 percent or greater deviation in fault current is identified. A 15 percent decrease in fault current should warrant a re-study of directional overcurrent elements used in communication aided protection scheme.

Document Name:

Likes: 0

Dislikes: 0

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

SCE&G agrees with the SERC PCS committee comments: "

Comments:

1) page 4, Please revise the Purpose and Facilities to clarify the scope.

a) Purpose: "To maintain the coordination of Protection Systems installed to protect detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults."

b) Facilities: "Protection Systems installed to detect and isolate Faults on protect BES Elements."

Also see comment #3 below. There are a large number of DP-TO interfaces and clarity on this interface is needed.

2) page 6 Rationale Option 2: augment ‘Planners and Planning Coordinators’ with ‘Transmission Owner’ so it reads "The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Owners, Transmission Planners, or Planning Coordinators." This makes it consistent with R1 1.1 itself, page 14 explanation.

3) page 13 DP Applicability is explained by ‘A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.’ A) In the vast majority of cases fault current contributions from DP networks are quite weak, usually the last to trip, and insignificant to BES coordination. B) BES Phase 2 Definition excluded networks below 50kV and at the least this should be acknowledged here. C) PRC-027-1 Draft 6 Applicability language is consistent with the PRC-005-2 language, for which PRC-005-2 Supplement states: "‘…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).’ The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System **protecting** that Element should then be included within this standard." D) Add language similar to B and C in the PRC-027-1 Supplemental Material.

4) page 17 second option: Please clarify the Fault current location for the 15% deviation trigger is the BES bus. This will help the GO and DP understand their responsibility. Please insert BES before Element in this sentence "The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which an a BES Element is connected. The drafting team intends for the 100kV or above BES bus to be the Fault current location."

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

n/a

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

AEP supports R1 & R3. AEP believes it is reasonable to have a process to develop Protection System settings for all BES elements, and to implement that process. AEP is willing to accept the inclusion of all BES protection systems in these requirements.

AEP does not support R2 as written in draft 6. AEP believes R2 should be limited to protection systems applied on BES Elements that electrically join Facilities owned by separate functional entities. It is reasonable to require a periodic review, as prescribed in R2, on protection systems applied to interconnecting elements, because an entity does not have knowledge of what changes are made by another entity that may affect protection system coordination.

AEP believes that R1 is sufficient to cover coordination of all internal protection systems. AEP has an existing process to review area coordination when system changes are made. All settings in the area that are affected by the change are reviewed and revised as necessary. Because of this process, it is not likely that any fault current comparisons would identify a 15% deviation at any buses. Thus, this requirement would become an administrative burden without any reliability benefit for internal protection systems.

AEP proposes that R2 be changed to read:
R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) with Protection System functions identified in Attachment A:

While AEP is supportive of the overall intent and direction of PRC-027-1, we have chosen to vote negative driven by our objections to R2, as stated above.

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment:

the HIGH VRF for Requirement R3 seems too high since failing to meet R1 (to develop the process for developing new and revised Protection System settings for BES Elements) has a MEDIUM VRF; failing to utilize this process should not have a VF that’s higher than not having the process in place to begin with.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Northeast Utilities - 3 -

Selected Answer:

Answer Comment:

1. We suggest that the drafting team consider the potential overlap of PRC-027-1 R1.1.1 and MOD-032-1, R1 and provide necessary clarification in the supplemental material.

2. R2, Option 2 has two actions associated with it, both of which have to be completed in one timeframe. The two actions are the fault current comparison against the baseline and the performance of a Protection System Coordination Study if the fault current comparison exceeds 15% or greater deviation. It is recommended that under this option, if an entity identifies a 15% or greater deviation in fault current value at a bus, the entity is given a set amount of time per element to complete a protection coordination study on all applicable elements at that bus.

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

ReliabilityFirst agrees that PRC-027-1 helps to alleviate the risk of insufficient coordination of Protection Systems installed to detect Faults on BES Elements and isolate those faulted Elements (such that the Protection Systems operate in the intended sequence during Faults). ReliabilityFirst offers the following comments related to the term "coordination" for the Standard Drafting Team's consideration:

1. **ReliabilityFirst notes that the term "coordination" used in Requirement 1, Parts 1.3.2 and 1.3.3 is not defined within PRC-027-1 or the NERC Glossary Terms. This term is also used within a number of other Reliability Standards where it is likewise undefined. As a result, and according to FERC precedent, the dictionary definition of the term "coordination" will control. As a result, the term "coordination" could reasonably be interpreted to refer to either the setting of Protection Systems *or* to communications between entities.**

To add clarity to PRC-027-1, ReliabilityFirst recommends replacing the term "coordination" with the term "Protection System Coordination." Listed below is ReliabilityFirst's proposed NERC Glossary definition of "Protection System Coordination" for the Standard Drafting Team's consideration:

***Protection System Coordination* - The setting of Protection Systems installed for the purpose of detecting and isolating Faults on BES Elements, such that the Protection Systems operate in a defined sequence in an effort to remove such Faults from the BES.**

1. **ReliabilityFirst recommends the following changes to Requirement 1, Parts 1.3.2 and 1.3.3 to incorporate this new definition of "Protection System Coordination" (highlighted in red below):**

1.3.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any Protection System Coordination Issue(s) or affirming that no Protection System Coordination issue(s) were identified.

1.3.3. Verify that identified Protection System Coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Document Name:

Likes: 0

Dislikes: 0

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer:

Answer Comment:

Regarding R2: NIPSCO believes that measurement criteria M2 for Protection System Coordination Studies (PSCS) is not very clear. Standard needs to provide a clear direction as to what is considered an acceptable form of evidence for PSCS.

Document Name:

Likes: 0

Dislikes:	0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

- Comments: Section R1.1: Consider adding additional clarity to the sub-requirement to limit the review to the modified BES Elements or BES Elements in the zone of protection. For example, the statement could be modified as follows: “A review and update of short circuit models for the modified BES Elements under study or BES Elements in the zone of protection.” This limits the scope of the short circuit model review to just the elements being studied.

Document Name:

Likes:	0
Dislikes:	0

Kayleigh Wilkerson - Lincoln Electric System - 5 -

Selected Answer:

Answer Comment:

LES suggests that the evidence required to meet R3 be limited and clearly defined. As currently drafted, the scope of potential evidence to demonstrate compliance with R3 would be difficult to anticipate and therefore unmanageable. Recommend the evidence be limited to entities providing short-circuit model updates (R1.1), Protection System setting reviews (R1.2), and Protection System setting coordination between owners for electrically-joined Facilities (R1.3).

LES recommends Option 2 of R2 be further clarified. It is not clear if a Protection System Coordination Study is required even if a fault current baseline hasn't deviated by 15% in 6 years. Additionally, it is also not clear what the scope of the Protection System Coordination Study is. To provide further clarity to R2 Option 2, LES suggests modifications similar to the following:

Compare present Fault current values to an established Fault current baseline in a time interval not to exceed six calendar years. A Protection System Coordination Study must be performed on the Elements connected to the bus where the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground). This Protection System Coordination Study must be completed within one calendar year of the Fault current comparison. The Fault current baseline will be updated to the present Fault current values only on the Elements for which the Protection System Coordination Study was performed.

Additionally, LES recommends protection system functions that are only enabled when other relays or associated systems fail be excluded from the R2 (e.g., overcurrent elements that are only enabled during loss of potential conditions). We feel that these protection system functions are used only as a contingency and should not fall within scope of the standard.

Document Name:

Likes: 0

Dislikes: 0

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer:

Answer Comment:

The BEPC believes that the same applicability exclusion used for PRC-001-1.1 (ii) or PRC-005 should be applied to PRC-027. The key is coordination at the overall wind farm interface after the power has been aggregated. Without this exclusion, the burden of the standard outweighs any reliability benefits provided.

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer:

Answer Comment:

The NSRF believes that the same applicability exclusion used for PRC-001-1.1 (ii) or PRC-005 should be applied to PRC-027. The key is coordination at the overall wind farm interface after the power has been aggregated. Without this exclusion, the burden of the standard outweighs any reliability benefits provided.

The DGR applicability exclusion from PRC-001-1.1 (ii) should be added to R2, R3 or to Attachment A. FERC would not let a current requirement go unaddressed. Similarly, the individual generator exclusion from PRC-001-1.1 (ii) cannot be ignored. As an example, the following could be added to either a requirement or Attachment A:

- Requirement R2 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

The exclusion is required to address the blanket inclusion of individual wind turbines under the new Bulk Electric System (BES) definition Inclusion 4 (I4) and wording in Requirement 2 that states “each BES Element with Protection System functions identified in Attachment A” are to be addressed.

Another alternative is the NSRF recommends an Applicability statement such as (PRC-005-2i):

- 4.1.4 Protection Systems for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:
- 4.1.4.1 Protection Systems for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or above.

The NSRF would like to see the words “NERC registered” added in front of the word “owner” to ensure that entities with multiple non-NERC joint owners avoid the unnecessary administrative burden of attempting to track entities with no NERC responsibilities. With PSE and possibly LSE deregistration, entities could be connected with non-NERC entities. The NERC paper process of exchanging information could become asymmetric as only one entity has legal requirements for actions and the other doesn’t. Adding “NERC registered” should reduce unnecessary administration and create a symmetric or level set of requirements between affected entities.

In order to take advantage of Requirement R2-Option 2, a fault current baseline must be established prior to the effective date. This sets entities up for the potential to do a considerable amount of work based upon the expectation that nothing will change between the approval date and the effective date. Given the degree of change with PRC-005, there is certainly some amount of apprehension in this regard. A better method would be to allow the entity to establish the baseline within one year after the effective date or allow a phased-in approach.

There is no requirement ensuring the Transmission Owner will share the model database or Fault current study results to allow Generation Owners and Distribution Providers to complete R2 Option 1, 2 or 3. The applicability section recognizes that the TO's are the typical entity maintaining the system model for Fault studies. NSRF prefers previous draft versions that required the TO to conduct fault studies on all buses, make comparisons and notify other entities if the fault current changed.

The 6-year frequency requirement could be relaxed to be more consistent with other relay maintenance activities or there should be more justification provided for the additional cost of more frequent analysis.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer:

Answer Comment:

We have separately submitted a Word redline with comments. However, PSEG's comments are summarized below. We would vote "Affirmative" if the SDT adopted the changes proposed in PSEG's redline.

- We propose that the SDT modify the definition of Protection System Coordination Study by limiting it to Protection Systems for BES Elements.
- We propose that the SDT add "Transmission Planner" to the Functional Entities in Section 4.1. This change is consistent with proposed changes to delete R1.1 and add R4 so that the Transmission Planner performs Fault current studies and makes them available to their TOs, GOs, and DPs in R4. As we note in the rationale for R4:

"Transmission Planners develop short circuit data bases per MOD-032-1 and utilize them in TPL-001-4 to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt. Since Transmission Planners develop and use short circuit databases, having other entities (TOs, GOs and DPs) use them could introduce errors. Therefore, Transmission

Planners should be required to calculate all Fault current values for its busses (an initial baseline and subsequent periodic updates) and make those available to its Transmission Owners, Generator Owners, and Distribution Providers."

- In R2, we eliminated the footnote in Option 2 because proposed R4 will result in an initial Fault current baseline established by the TP on or before the effective date of the standard. Given this, when would an entity's first PSCS need to be performed for its Attachment A devices under R2? For example, if Option 2 is selected, is the first PSCS required when the baseline fault current increases by 15 percent or greater?

- Other changes in language in R1, R2, and R3 are explained in comments in the redline.

Document Name: pseg redline of PRC-027-1_Draft_6_09.09.15.docx

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

(1) Please address each of our following comments as many of them were not addressed in the last ballot action. If these comments are not addressed, Seminole may revise its ballot vote from affirmative to negative upon the next ballot action.

(2) This Standard references the terms “BES Elements.” In reviewing the NERC Glossary, there are many references to merely “Elements” without the preceding “BES” adjective, i.e., Remedial Action Scheme definition. What is the difference between “BES Elements” and “Elements” (without the BES)? Is the term “Element” without BES reference to elements that are non-BES, and if that is the case, does subpart “e.” of the RAS definition apply to non-BES Elements as there is no preceding “BES”? “BES Elements” and “Elements” are still both utilized in the Standard. Per discussions with the drafting team, it was stated that this is accidental and that there is no difference and that the team will clean these up to merely state “Elements” in the next version.

(3) In R2, if a review was performed on March 1, 2017 and an entity had 6 calendar years in which to complete the review, is that 6 full calendar years? Meaning, would an entity not have to complete another review until December 31, 2023? Could you please include the above example, or an example akin to the above in the guidelines as we want to confirm we understand that 6 full calendar years are allowed, which means that more than 72 months between tests could be taken under certain timing circumstances?

(4) In R1 Part 1.5.3, this Requirement merely states that the coordination issues need to be “addressed” prior to implementation. We have two questions on this requirement, the first being that after reviewing the supplemental guidance material, that under certain circumstances, such as where additional system modifications are needed, that such modifications do not need to take place before the settings changes if the entity didn’t originally place those modifications into the scope of the settings changes project. Because the Requirement does not require the modifications to take place in any future time, can the drafting team describe in more detail how these issues are “addressed prior to implementation”? In discussions with the drafting team regarding what “addressed” means is that any coordination issues need to be agreed upon between the entities and the entities must agree to the implementation actions and a timeframe for implementation, and depending on the circumstances,

“outstanding” updates can be implemented after implementation of proposed Protection System changes. Please confirm that this is correct.

(5) In the Supplemental Material section, there are references to the terms “BES Protection System” and “Protection System.” The Standard applies to “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted elements.” For purposes of this Standard, is a BES Protection System a Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted elements? There are still references to “BES Protection System” and “Protection System.” In discussions with the drafting team it was noted that all of these references were going to be cleaned up to merely state “Protection System”. Please confirm.

(6) In Requirement R1, is the 15% value 15.% with two significant figures in that if we have a deviation of 14.6% we need to perform an evaluation as it rounds up to 15% or are there more significant figures, i.e., 15.0%? This was discussed again with the drafting team that our comment wasn’t answered in the guidance, but per a phone conversation it was stated that anything above 15.000000000 (infinity) is a violation. We’d prefer the NERC drafting teams begin honoring significant digits as it’s not a difficult clarification and it makes compliance problematic because we can’t tell if it’s intentional or not when the drafting teams stop at a certain point. Therefore, this request is still out there, please place as many digits the team feels is significant as we will keep making this comment on every future drafted Standard, e.g., is 15.000% enough for the drafting team?

(7) In Requirement R2, if an entity uses the time based option and uses a recent short-circuit study for its baseline study, does the 6-year option 2 time frame start from the time of enforcement of the Standard or from the date the short-circuit study was finalized? The answer to this question does not appear to be in the Requirement. For Option 2, per our discussion, if a Protection System Coordination Study is performed today, the 6 year timeframe doesn’t begin until the enforcement date of the Standard, correct? We are still somewhat unclear as to when the Fault current baseline comparison needs to be performed however. For example, does a Fault current baseline need to be performed every 6 years? There is some language in the Rationale box on this issue, but that language says “may” and not “shall” so it appears this isn’t a requirement but merely a suggestion

(8) “Electrically joined Facilities” is not defined. Per past discussions, the intent appears to be to describe Facilities that are electrically joined AND are physically joined. Meaning, that if one Facility is 10 miles down the transmission line from another Facility, albeit “electrically joined” by electrons moving through both Facilities, the Facilities are not physically touching, and therefore, not covered by the intent of “electrically joined Facilities” under this Standard. Is this correct?

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

1) Manitoba Hydro suggests that the title of this standard is changed from "Coordination of Protection Systems for Performance During Faults" to: "Protection System Coordination Performance During Faults"

2) For section 1.3.4.2, "Misoperation investigation" may be better replaced by "Protection System operation investigation"

3) For R2, there seems to be no incentive (nor requirement) for entities to go with option 2 since they still have to do this study within 6 years regardless the level of fault current changes anyway.

Document Name:

Likes: 0

Dislikes: 0

Jay Barnett - Exxon Mobil - 7 -

Selected Answer:

Answer Comment:

The Supplemental Material states, "The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current availability upon request by the Distribution Provider or Generator Owner," however, there is nothing in the draft of PRC-027-1 that requires this and that would ensure this is done in a timely manner. This draft might introduce the circumstance where the GO has the responsibility to periodically compare data that the TO has and maintains. The Standard should require TOs to respond to GO requests for Fault current data in a timely manner so that the GO can perform coordination studies if necessary. Another approach would be to transfer the responsibility of performing the periodic comparisons to the TOs. If the fault current changed by 15%, then the TO would notify the affected GO so that a coordination study would be performed. The same issue would exist for small TOs that do not maintain wide-area system models.

Proposed Revision:

R2.1. Upon discovery of a change in Fault current of a BES Element owned by another GO, TO, or DP, each TO shall provide the updated Fault current values to the affected owners within 90 calendar days of discovery.

OR

R2.1. Each TO that maintains Fault current values for BES Elements owned by other GOs, TOs, or DPs, shall respond to requests for such information from the GO, TO, or DP within 90 calendar days.

Also, Requirement 3 should be limited to the attributes listed in Requirement 1 in order to have a clear and consistent measure for compliance. As written, auditors would have to become familiar with each entity's entire coordination process in order to determine compliance. Instead each entity should only have to demonstrate compliance with those attributes which the Standard Drafting Team has determined are "must have" to ensure proper coordination, as described in Requirement R1.

Proposed Revision:

R3. Each TO, GO, and DP shall utilize a process that contains the minimum attributes established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Salt River Project (SRP) has concern over R1 part 1.1 and 1.2. As written, R1 calls for a “process for developing new and revised Protection System settings”. Parts 1.1 and 1.2 requires a “review and update of short-circuit models” and a “review of the developed Protection System settings”, respectively. The process defined in R1 should not have to include either review. SRP recommends changing part 1.1 and 1.2 to reflect “A methodology to evaluate ...”. In previous conversations with the SDT NERC staffer, it was communicated that the intent of this requirement was to include a methodology, however the previous draft removed the language that would have signified a methodology was required. If the intent is that a process rather than the actual review is included, it should read as such.

Document Name:

Likes: 1 Tarantino Joe On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1,
Ke

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter

Chris Scanlon

Segment

1

Entity

Exelon

Region(s)

Selected Answer:

Answer Comment:

The applicability of the standard needs to be clarified so that dispersed resources at the individual resource prior to the point of aggregation are not subject to the standards requirements. In the transition from PRC-001.1ii., the exclusion for dispersed resources appears to have been improperly dropped from PRC-027-1. The PRC-027-1 mapping document lists PRC-001.1ii R3.1 and the dispersed resources sub-bullet exclusion but we cannot find a record indicating that there was discussion resulting in a deliberate intent to remove the exclusion in the transition from PRC-001.1ii to PRC-027-1. While a change to applicability prior to a final ballot is considered a substantive change in Section 4.14 of Standards Process Manual, we note that per the same section, "Where there is a question as to whether a proposed modification is "substantive," the Standards Committee shall make the final determination". We therefore request that the SDT bring this issue to the Standards Committee for consideration and include the dispersed generation exclusion in PRC-001.1ii in PRC-027-1 prior to final ballot.

Other options to address this concern could include, clarification in the Supplementary Material section, notes to auditors in the RSAW or the submission by the SDT of a SAR to change the applicability consistent with the dispersed generator exclusion as currently included in PRC-001-1ii .

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

We would like to see an exception for distributed resources similar to what project 2014-01 is working on for other standards. Typically distributed resources do not look out to the transmission system, but unless they are excluded this will need to be examined and documented.

Document Name:

Likes: 0

Dislikes: 0

Spencer Tacke - Modesto Irrigation District - 4 -

Selected Answer:

Answer Comment:

Hi,

I really believe the time period options for doing a Protection Coordination Study specified in R2 (Option 1 or Option 2) are much too large. When I used to attend the WECC Meetings on a regular basis, I remember how a high percentage of the major system outages were tied to mis-coordination or mis-operation of the protective relay systems of the various neighboring utilities. As the member’s protection systems are critical to the reasonable reliability of the interconnected system, waiting six years to do another fault current check for the 15% threshold is unreasonable, or allowing no threshold current check but with a fixed 6 year time period between coordination studies, is asking for trouble. I would strongly support a one year period as the required time to do a new Protection System Coordination Study for each member's BES. Remember, NERC requires annual Transmission Planning Assessments (TPL Standards), so we should not accept any lower of a standard for a Protection System Coordination Study. Thank you.

Sincerely,

Spencer Tacke

Senior Electrical Engineer

Modesto Irrigation District

209-526-7414

spencert@mid.org

.

Document Name:

Likes: 0

Dislikes: 0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5 -

Selected Answer:

Answer Comment:

It appears that if Option 1 is selected for R2, an entity has six years from the effective date to complete the study and also evidence for R3 would not be required until this same date. Please confirm.

Functional Entities, under Applicability and each requirement, should include Transmission Planners.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Option 2 of R2 is meant to allow an entity to periodically check for a 15 percent of greater deviation in fault current. This option allows the entity to choose an interval of up to six calendar years to perform the fault current comparisons (this is derived from the PRC-027-1 supplemental material). The intent of Option 2 is not immediately clear without reading supplemental material. Given that compliance is measured only by the text of the requirement, R2 Option 2 should be clarified to indicate that if the 15 percent fault current baseline hasn't been exceeded, a protection coordination study isn't required even it if has been more than six calendar years.   Or is the intent of the drafting team to state that if the 15 percent baseline threshold hasn't been exceeded a coordination study isn't required?

Additionally, the evidence retention section would benefit from clarification. There could be possible confusion with the 6 year interval of the standard versus a possible audit interval of 3 years.

Another opportunity for improvement would be to align the intervals with the intervals identified in PRC-019, which would be beneficial to GOs.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:

Answer Comment:

See Comments from ACES

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:

Answer Comment:

See Comments from ACES

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer:

Answer Comment:

SMUD supports Salt River Project comments.

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment:

In the Supplemental Material section, there are concerns about the following paragraph: “A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.” If the generator is not a BES generator, or the generation plant is not a BES plant, the associated Protection Systems should not be under the purview of this standard unless, perhaps, they serve to provide a blocking signal to other Protection Systems associated with the BES Element or their clearing is necessary for the other Protection Systems associated with the BES Element to operate properly. For small non-BES generation, the Transmission Owner may configure its Protection Systems to properly respond with or without the small generator(s) connected. In these cases, clearing the generator(s) is arguably more about safety (isolating sources of energization) and not coordination.

It sounds like the only triggers for conducting a Protection System Coordination Study (PSCS) are the following: (1) triggered by Requirement R2, (2) triggered by the need to establish a baseline for Requirement R2 for new BES Elements or new BES Facilities, or (3) triggered by the need to establish a baseline for Requirement R2 when transitioning between Options 1 and 2. Otherwise, if there are Protection System changes, or if there are changes to existing BES

Elements, it sounds like a PSCS is not (necessarily) required, provided that the other elements identified in Requirement R1 are addressed. Is this the drafting team’s intention? If a PSCS will be required for other cases, this should be more clearly identified.

The verbiage in Requirement R2, Option 2, is a little unclear. For example, if Fault current values are compared within four calendar years, and the percentage change is less than 15%, does this reset the maximum six calendar year interval under Option 2?

Under Requirement R1, Part 1.3.4, Tacoma Power suggests appending "…scenarios such as the following:"

The Rationale for Requirement R1 includes a note about internal documentation. Tacoma Power had hoped that documentation would not explicitly be required in a scenario in which one engineering workgroup is responsible for Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, especially when those functional entities are part of the same company/organization. There is concern about the amount of extra documentation that may be involved. Furthermore, when different functional entities are part of the same company/organization, it may not be 100% clear where the DP vs. TO or TO vs. GO line should be drawn; by contrast, the same internal documentation would not be required for internal TO-TO interaction.

The emphasis of this standard should only be to show that there is not miscoordination. It is a little awkward, but Tacoma Power suggests that the Purpose statement could be reworded to the following (CAPS added to identify suggested rewording): "To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems DO NOT operate in the UNintended sequence during Faults." Similarly, the definition of a PSCS could be reworded to the following: "An analysis to determine whether Protection Systems DO NOT operate in the UNintended sequence during Faults." Requirement R1 could be reworded to the following: "...such that the Protection Systems DO NOT operate in the UNintended sequence during Faults..."

Compared to Requirement R1, Tacoma Power is not convinced that the justification has been made for a High VRF for Requirement R3. Failing to implement one piece of the process established under Requirement R1, even for one BES Element, coupled with no graduated VSLs (see subsequent comment), would result in the maximum potential penalty.

Tacoma Power believes that the drafting team should leverage the Lower, Moderate, and High VSLs for Requriement R3. FERC's VSL G1 only states that the VSL assignment should not have the UNINTENDED consequence of lowering the current level of compliance. Furthermore, the scope of applicability of PRC-027-1 is much greater than PRC-001-1, so it is reasonable for PRC-027-1 to leverage the Lower, Moderate, and High VSLs, even though PRC-001-1 did not.

An example of a Protection System Coordination Study in the Supplemental Material section might be helpful.

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment:

R1 – Generally think there should be a bit more detail or definiation provided to "Protection System settings" that require reviewing. Does this just include element set values? Or does it also include logic settings? Drawings versus output contact programming? What about communications equipment? Keeping this wide open and letting entities define goes back down the PRC-005-1 road where some entities had much higher testing and maintenance standards, but were also held to that higher standard and punished harshly when even falling just short.

R2 – Generally believe that giving the option of using fault studies or a time interval is for determining when to review coordination in R2. However, believe that if using the baseline fault studies, then the entity should have a shorter period between performing such studies. One issues with the baseline fault studies is that coordination studies may go for an additional 6 years, even if the 6 year study shows the fault current at just below the 15% threshold. I believe a 3 year or 4 year interval would be more reasonable. Otherwise, why not just use the baseline method since it too is on a 6 year interval.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Reclamation suggests that the drafting team reorder R2 and R3 for clarity. This would allow the standard to follow a logical order requiring an entity to have a system protection coordination process (R1), follow it (R2), and periodically update system protection coordination studies for functions in Attachment A (R3).

Reclamation also suggests that the drafting team update R1.3.4 to clarify that communications resulting from unforeseen circumstances may be "after-the- fact notifications" rather than requiring advance communication. This would clarify that Protection System owners do not need to wait for confirmation from owners of electrically-joined Facilities before revising Protection System settings due to unforeseen circumstances. Reclamation believes that waiting for coordination with owners of electrically joined facilities in these situations could increase risks to BES reliability from faulty Protection System settings that are discovered during commissioning, misoperation investigations, and maintenance or component failures which should be addressed immediately. Reclamation suggests that this should be clear in the requirement itself, not merely mentioned in the supplemental material.

Finally, Reclamation suggests that the drafting team update M3 to provide examples of how an entity would demonstrate that it is following the process required by R1 to include more detail regarding example evidence to show compliance with each subrequirement.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Reclamation suggests that the drafting team reorder R2 and R3 for clarity. This would allow the standard to follow a logical order requiring an entity to have a system protection coordination process (R1), follow it (R2), and periodically update system protection coordination studies for functions in Attachment A (R3).

Reclamation also suggests that the drafting team update R1.3.4 to clarify that communications resulting from unforeseen circumstances may be “after-the- fact notifications” rather than requiring advance communication. This would clarify that Protection System owners do not need to wait for confirmation from owners of electrically-joined Facilities before revising Protection System settings due to unforeseen circumstances. Reclamation believes that waiting for coordination with owners of electrically joined facilities in these situations could increase risks to BES reliability from faulty Protection System settings that are discovered during commissioning, misoperation investigations, and maintenance or component failures which should be addressed immediately. Reclamation suggests that this should be clear in the requirement itself, not merely mentioned in the supplemental material.

Finally, Reclamation suggests that the drafting team update M3 to provide examples of how an entity would demonstrate that it is following the process required by R1 to include more detail regarding example evidence to show compliance with each subrequirement.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Paul Nauert	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
David Greene	SERC staff	SERC	10

Voter Information

Voter	Segment
David Greene	10

Entity	Region(s)
SERC	SERC

Selected Answer:

Answer Comment:

1) page 4, Please revise the Purpose and Facilities to clarify the scope.
a) Purpose: “To maintain the coordination of Protection Systems installed to protect Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate
in the intended sequence during Faults.”
b) Facilities: “Protection Systems installed to protect BES Elements.”

Also see comment #3 below. There are a large number of DP-TO interfaces and clarity on this
interface is needed.

2) page 6 Rationale Option 2: augment ‘Planners and Planning Coordinators’ with ‘Transmission
Owner’ so it reads “The Fault current baseline values can be obtained from the short-circuit
studies performed by the Transmission Owners, Transmission Planners, or Planning Coordinators.”
This makes it consistent with R1 1.1 itself, page 14 explanation.

3) page 13 DP Applicability is explained by ‘A Distribution Provider may provide an electrical
interconnection and path to the BES for generators that will contribute current to Faults that
occur on the BES. If the Distribution Provider owns Protection Systems that operate for those
Faults, it is important that those Protection Systems are coordinated with other Protection Systems
that can be impacted by the current contribution to the Fault of Distribution Provider.’ A) In
the vast majority of cases fault current contributions from DP networks are quite weak, usually the
last to trip, and insignificant to BES coordination. B) BES Phase 2 Definition excluded networks

below 50kV and at the least this should be acknowledged here. C) PRC-027-1 Draft 6 Applicability
language is consistent with the PRC-005-2 language, for which PRC-005-2 Supplement states: "'…that
are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers,
etc.).' The drafting team intends that this standard will follow with any definition of the Bulk
Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection
System protecting that Element should then be included within this standard." D) Add language
similar to B and C in the PRC-027-1 Supplemental Material.

4) page 17 second option: Please clarify the Fault current location for the 15% deviation trigger
is the BES bus. This will help the GO and DP understand their responsibility. Please insert BES
before Element in this sentence "The second option allows the entity to periodically check for a 15
percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an
established Fault current baseline for Protection Systems at each bus to which a BES Element is
connected. The drafting team intends for the 100kV or above BES bus
to be the Fault current location."

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter	Segment
Colby Bellville	1,3,5,6
Entity	**Region(s)**
Duke Energy	FRCC,SERC,RFC

Selected Answer:

Answer Comment:

Upon our review of the most recent draft of the proposed PRC-027-1 standard, we have significant concerns regarding the expectations outlined in R1, subpart 1.2. In part 1.2, the applicable Functional Entity is required to conduct or ensure some type of review is done on its Protection System settings. While the latitude that is given to the industry on how and what type of review they are to implement is recognized, we feel that specifically mandating a quality review is unnecessary. The requirement of ensuring that quality reviews are executed is not currently included in other Protection and Control standards, and is not mandated in other standard families (with the exception of CIP-014). We do not disagree with the practice of quality assurance, however, we do not support the practice of requiring an entity to do so in a Reliability Standard. Duke Energy recommends the removal of subpart 1.2 from R1.

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Jonathan Hayes	Southwest Power Pool Inc	SPP	2
Robert Gray	Board of Public Utilities of Kansas City, Kansas	SPP	3
Michael Jacobs	Camstex	NA - Not Applicable	NA - Not Applicable
stephanie Johnson	Westar Energy, Inc	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

We have a concern about the mentioning of the Transmission Planner and Planning Coordinator in the Requirement R2 Rationale Box and those entities performing the calculations for the Fault current through short circuit analysis. The Rationale Box for Requirement R2 states “The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators”. We would suggest the removal of those entities from the Rationale Box because they aren’t include in the applicability section of the standard. Additionally, we feel that the fault current calculation has been addressed in the scope of the TPL Documentation. In that documentation, it is understood that the Transmission Planner or Planning Coordinator will conduct the fault current analysis on the BES facilities however, the Transmission Planner

	would have to coordinate with the owners and determine which protection systems would be impacted.
Document Name:	
Likes:	0
Dislikes:	0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer:

Answer Comment:

I believe it would be appropriate to include the Transmission Planner as an applicable entity for R2 purposes as they typically maintain the fault current/short circuit values at the buses.

I had to reread R2 a couple of times to be clear that the coordination study required as part of Option 2 only applies to the buses where the deviation exceeds 15% and not required of all the buses. If an opportunity exists, a minor clarifying edit would be recommended.

in R2, the standard speaks to a deviation at a bus to which the Element is connected. Is this intended to be a bus that is part of the BES? I'm thinking of how this would be applied at a generating plant where there is the transmission voltage level bus, the generating plant bus (e.g. 18 kV), lower voltage level buses within the plant, etc. I'm wondering how this aspect would be applied in practice at a plant. Perhaps clarifying edits in the requirement language and accompanying discourse in the rationale would help clarify this…

Document Name:

Likes: 0

Dislikes: 0

Louis Guidry - Louis Guidry On Behalf of: John Lindsey, Cleco Corporation, 6, 5, 3, 1
Michelle Corley, Cleco Corporation, 6, 5, 3, 1
Robert Hirchak, Cleco Corporation, 6, 5, 3, 1
Stephanie Huffman, Cleco Corporation, 6, 5, 3, 1

Selected Answer:

Answer Comment:

The definition of Power System Coordination Study is defined as an analysis of the operating sequence. Our interpretation of the definition is that we have to model the relay action and demonstrate that it operates in the intended sequence. Cleco uses fault simulations to develop the settings. We do not model the relays in our short-circuit program to demonstrate the relay action.

2. The standard requires an internal review of the developed settings. Who is going to review the settings currently develop? Relay settings are an art due to the compromised required because of so many unique problems. No two people are going to solve the problem exactly the same. Should two people develop the settings and compare results?

3. The standard requires a review of the short-circuit model prior to developing settings. What constitutes a valid review?

4. Requirement 1.3 says we get a response from other owners prior to implementing settings on associated BES elements. How much time before Cleco responds is required? How much time do we have to wait for a response? What if neighboring entity request a response for many of our associated systems at once?

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

Please state that when a fault current baseline is first established we are not required to show a coordination study for every protection scheme on our system. Please state that utilities are not required to show a coordination study if the baseline continues to show a fault current change less than 15%?

Requirement R2 option 2 states “Fault current values (either three phase or phase to ground) at a bus to which the Element is connected” where the RSAW states “Fault current comparison and results for each BES Element”. The RSAW and Standard should match language as closely as possible. In this case the standard states bus faults and the RSAW evidence specifies each element which is more than just a bus. It may be wise to delay industry RSAW reviews until the standard language is in a more finalized state.

Consider adding a modification to R2. There should be an allowed time line for a coordination study to take place after the 15% fault current threshold has been identified as being exceeded. This presents a risk many could step into unwittingly when the identification is close to the 6 year interval. There are circumstances where fault currents may not change until close to this 6 year interval due to system changes that may not be foreseen. We suggest the requirement include a two year window after a 15% change is identified.

Please provide a definition or examples to clarify what is considered “electrically-joined Facilities”. For example, if a line and both terminals and protection is owned by entity A at sub 1 and sub 2. All other equipment at sub 1 is owned by entity B. All equipment at Sub 2 is owned by entity A. Is sub 2 “electrically-joined”?

The RSAW in the sections for R1 and R3 states: “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation”. We request a provision in the Standard allowing if all separate functional entities within an organization have access to the same internal documentation, then the communication aspects are not required.

In a situation where utility A does work for another utility B on their transmission system protection equipment and utility A owns all the other surrounding protection systems, please clarify how the communication evidence would change with coordination work since utility A is making all the coordination decisions. Is it acceptable to show utility A has all utility B protection system settings internally stored? Does this make utility A responsible for utility B compliance?

For a facility that has multiple bus voltages such as 115kV, 230kV and 345kV and if the fault current baseline exceeds 15% on just the 115kV bus does this mean just the elements connected to the 115kV bus must have a coordination study but not the 230 or 345kV buses?

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

Please state that when a fault current baseline is first established we are not required to show a coordination study for every protection scheme on our system. Please state that utilities are not required to show a coordination study if the baseline continues to show a fault current change less than 15%?

Requirement R2 option 2 states “Fault current values (either three phase or phase to ground) at a bus to which the Element is connected” where the RSAW states “Fault current comparison and results for each BES Element”. The RSAW and Standard should match language as closely as possible. In this case the standard states bus faults and the RSAW evidence specifies each element which is more than just a bus. It may be wise to delay industry RSAW reviews until the standard language is in a more finalized state.

Consider adding a modification to R2. There should be an allowed time line for a coordination study to take place after the 15% fault current threshold has been identified as being exceeded. This presents a risk many could step into unwittingly when the identification is close to the 6 year interval. There are circumstances where fault currents may not change until close to this 6 year interval due to system changes that may not be foreseen. We suggest the requirement include a two year window after a 15% change is identified.

Please provide a definition or examples to clarify what is considered “electrically-joined Facilities”. For example, if a line and both terminals and protection is owned by entity A at sub 1 and sub 2. All other equipment at sub 1 is owned by entity B. All equipment at Sub 2 is owned by entity A. Is sub 2 “electrically-joined”?

The RSAW in the sections for R1 and R3 states: “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation”. We request a provision in the Standard allowing if all separate functional entities within an organization have access to the same internal documentation, then the communication aspects are not required.

In a situation where utility A does work for another utility B on their transmission system protection equipment and utility A owns all the other surrounding protection systems, please clarify how the communication evidence would change with coordination work since utility A is making all the coordination decisions. Is it acceptable to show utility A has all utility B protection system settings internally stored? Does this make utility A responsible for utility B compliance?

For a facility that has multiple bus voltages such as 115kV, 230kV and 345kV and if the fault current baseline exceeds 15% on just the 115kV bus does this mean just the elements connected to the 115kV bus must have a coordination study but not the 230 or 345kV buses?

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2007-06 PRC-027-1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1

Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer:

Answer Comment:

The parenthetical phrase in sub-Part 4.1.3 of the Applicability is not necessary and should be deleted.   FPA 215 already ready limits the applicability of all reliability standards to the Bulk Power System and believe that NERC has revised the BES definition so that it should, either through application of bright line criteria or through the NERC or FERC exception process, encompass only those Elements and Facilities that are subject to FPA 215.

It should also be noted that, in this version the word “its” is deleted from Requirement 1 but that the Rationale for Requirement R1 uses the word “their” while Measure 1 uses the word “its”. We suggest changes be made so that all contain consistent verbiage. We believe that an entity can only be responsible for Protection System(s) it owns and would prefer this be explicitly indicated in the requirement(s).

As defined in the NERC Glossary, the Reliability Coordinator is the entity that is the highest level of authority who is responsible for the reliable operation of the

Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and Real-time operations. The Reliability Coordinator has the purview above and beyond that of a Transmission Operator that is broad enough to enable the calculation of Interconnection Reliability Operating Limits. Because new relay settings or revisions to relay settings can impact IROL calculations, the Reliability Coordinator must be aware of any new relay settings or revised relay settings in advance of their implementation.

For these reasons the standard needs to require that each Transmission Owner, Generator Owner and Distribution Provider notify the Reliability Coordinator that it is developing new or revised relay settings. The revision should also allow for the Reliability Coordinator to provide comments on the new or revised relay settings. To capture this, we suggest the following revision to R1:

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A review and update of short-circuit models for the BES Elements under study.

1.2. A review of the developed Protection System settings.

1.3. Provide new or revised Protection System settings to the Reliability Coordinator.

1.3.1 Respond to the Reliability Coordinator's comments regarding the proposed new or revised Protection System settings by resolving any coordination issue(s) or affirming that no coordination issue(s) were identified.

1.4. For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.4.1. Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

Also, to clarify and reinforce the nature of the broader protection coordination concern, suggest the following modification to the Purpose:

"To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection

Systems operate in the intended sequence during Faults without causing an inadvertent adverse impact anywhere on the BES."

We suggest that the drafting team review PRC-027-1 R1 Part 1.1 and MOD-032-1, R1 for a potential overlap, and if necessary provide clarification in the supplemental material.

R2, Option 2 has two actions associated with it, both of which have to be completed in one timeframe. The two actions are the Fault current comparison against the baseline and the performance of a Protection System Coordination Study if the fault current comparison exceeds 15% or greater deviation. It is recommended that under this option, if an entity identifies a 15% or greater deviation in Fault current value at a bus, the entity is given a set amount of time per element to complete a protection coordination study on all applicable elements at that bus.

In many cases, smaller entities that are interconnected to larger TOs do not develop their own Protection System settings. These settings are provided to them by the interconnecting TO and mandated to be implemented through Interconnection agreements. R1 should be revised to recognize these instances, including the Rationale for Requirement R1 words related to a "single protective relaying group performing the work for multiple functional entities," as a single group may be responsible for the process for multiple owners of BES Elements. The note should also be included in the Requirement and Measure as internal documentation will be used to determine the coordination aspects of Part 1.3.

Requirement R3 needs a "trigger" to initiate the process described therein. Suggest revising Requirement R3 to read:

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that determines a need for new or revised Protection System settings shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

To avoid confusion between modeling and protection short circuit modeling, suggest adding the word "protection" to make the term used in the standard "protection short circuit".

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment: N/A

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE recommends deleting the comment regarding ownership in the Functional Entities section since there is no need with risk-based compliance.

In the Evidence Retention section, Texas RE recommends changing the statement “since the last audit” to “since the last audit of these requirements.”

Document Name:

Likes: 0

Dislikes: 0

Kenn Backholm - Snohomish County PUD No. 1 - 6 -

Selected Answer:

Answer Comment:

Public Utility District No. 1 of Snohomish County supports Salt River Project comments.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:

Answer Comment:

1) Hydro One Networks Inc. agrees with the NPCC and recommends that the NERC SDT provides clarification on the overlap of requirements between MOD-032-1, R1 (to develop short-circuit modelling data requirements) and PRC-027-1, R1 (to establish a process which includes a review and update of short-circuit models).

2) Requirement R2, Option 2, entails two actions: 1) a fault current comparison against a previously established baseline be performed, and 2) a Protection System Coordination Study be performed if the results of the comparison study exceed a deviation 15%. Presently, both these actions need to be performed within the same timeframe. However, Hydro One Networks Inc. agrees with the NPCC in that a separate time period should be allotted for an entity to complete a protection coordination study on all associa0ted elements on a bus, if a deviation of 15% or greater in the available fault current comparison is identified.

3) Further, Hydro One Networks Inc. also recommends that in the interest of clarity, the two actions within Option 2 of requirement R2 be separated out.

Document Name:

Likes:	0
Dislikes:	0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter	Segment
Carol Chinn	4
Entity	**Region(s)**
Florida Municipal Power Agency	

Selected Answer:

Answer Comment:

1. From a standards development process perspective, FMPA recognizes that there was a fair amount of industry outreach recently on this Project. Yet, given the low results (<40%) in the prior balloting, a written “consideration of comments” would have been helpful. Plus, is it surprising that this round of questions only addresses the “Attachment A” and the “Implementation Plan” and not the actual standard language.

These few questions will not necessarily gather the input needed by the SDT, in case additional improvements are needed.

2. Requirement 1.3.4 has 4 sub parts that can drive auditors to require registered entities to prove the negative. Would suggest that the four sub parts be not listed as such and instead just be collapsed into the sentence. That will reduce the likelihood that auditors will feel compelled to ask for “specific supporting evidence to prove the negative” which we were told during outreach was not the intent of the SDT.

Part 1.3.4 *Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:*

1.3.4.1. *Implementation or commissioning.*

1.3.4.2. *Misoperation investigations.*

1.3.4.3. *Maintenance activities.*

1.3.4.4. *Emergency replacements required as a result of Protection System component failure.*

3. FMPA has previously commented that the speed at which faults are cleared is very important to reliability, and does not understand why sequence is call out in the standard and associated definitions as being more important. FMPA recommends the SDT consider adding language to R1 that requires review of Protection System settings with regard to critical clearing time.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE recommends deleting the comment regarding ownership in the Functional Entities section since there is no need with risk-based compliance.

In the Evidence Retention section, Texas RE recommends changing the statement “since the last audit” to “since the last audit of these requirements.”

Texas RE is concerned there is no time frame for entities to provide settings or response to settings in R1.3 The implication is that setting should be provided before implementation by using the word “proposed” but R1.3.2 does not discuss any timeframe for a response. R1.3.4 does not discuss a time frame for communication of revised settings in an unforeseen circumstance.

The footnote for R2 could cause confusion. It is not clear that an Entity should not exceed six years between either performing a Study or comparing Fault current values. If an entity changes options before the six year mark, a Study should be done at that time to establish the baselines.

Texas RE recommends changing the severe VSL for R2 to “The responsible entity failed to perform Option 1, Option 2 or Option 3, in accordance with Requirement 2 for each element.”

Document Name:

Likes: 0

Dislikes: 0

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer:

Answer Comment: Abstain

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment:

1. From a standards development process perspective, we recognize that there was a fair amount of industry outreach recently on this Project. Yet, given the low results (<40%) in the prior balloting, a written “consideration of comments” would have been helpful. Plus, is it surprising that this round of questions only addresses the “Attachment A” and the “Implementation Plan” and not the actual standard language. These few questions will not necessarily gather the input needed by the SDT, in case additional improvements are needed.

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment:

1. From a standards development process perspective, we recognize that there was a fair amount of industry outreach recently on this Project. Yet, given the low results (<40%) in the prior balloting, a written “consideration of comments” would have been helpful. Plus, is it surprising that this round of questions only addresses the “Attachment A” and the “Implementation Plan” and not the actual standard language. These few questions will not necessarily gather the input needed by the SDT, in case additional improvements are needed.

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Information

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Voter Information

Voter	Segment
Patricia Robertson	1
Entity	**Region(s)**
BC Hydro and Power Authority	

Selected Answer:

Answer Comment:

The requirement to coordinate protective relay settings has existed since the first power systems were built. BC Hydro, like all utilities, has been coordinating their protection systems as part of their normal practice and has a process for setting development, review and implementation on its protection systems. While the requirements in Draft 6 of PRC-027-1 are not substantially different than standard industry practice, proving annual compliance with these requirements (to the satisfaction of lawyers) will impose a large administrative burden. The original focus of PRC-001 made sense in that there are always communications and data gathering issues that make coordinating protection systems across different utilities more challenging than coordinating within one's own system. The new draft standard focuses too much of the utility's time and effort on proving compliance on a process that typically works well, which reduces the amount of time and effort that can be spent on areas where more time and money should be spent.

Document Name:

Likes: 0

Dislikes:	0

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Information

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Voter Information

Voter	Segment
Ben Li	2
Entity	**Region(s)**
Independent Electricity System Operator	NPCC

Selected Answer:

Answer Comment:

The Planning Coordinator, Reliability Coordinator, and Balancing Authority must be notified when new or revised protection settings are developed.

As defined in the NERC Glossary, the Planning Coordinator is the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems. Because the Planning Coordinator is responsible for the coordination and integration of protection systems, it must be aware of any new relay settings or revised relay settings in advance of their implementation.

As also defined in the NERC Glossary, the Reliability Coordinator is the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The

Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision. Because new relay settings or revisions to relay settings can impact IROL calculations, the Reliability Coordinator must be aware of any new relay settings or revised relay settings in advance of their implementation.

Finally, draft requirements in the proposed TOP-009-1 reliability standard require that the Balancing Authority ensure that "… its personnel responsible for Reliable Operation of its Balancing Authority Area have knowledge of operational functionality and effects of Composite Protection Systems and Remedial Action Schemes that are necessary to perform its Real-time monitoring in order to maintain generation-Load-Interchange balance." Accordingly, Balancing Authorities will need to be provided with new or revised Protection System settings to fulfill its obligations under TOP-009-1.

Therefore, the standard needs to require that each Transmission Owner, Generator Owner and Distribution Provider notify the Planning Coordinator, Reliability Coordinator, and Balancing Authority that it is developing new or revised relay settings. The revision should also allow for the Planning Coordinator or Reliability Coordinator to provide comments on the new or revised relay settings. To capture this, the ISO/RTO Council Standards Review Committee suggests the following revision in R1:

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: ***[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]***

1.1 A review and update of short-circuit models for the BES Elements under study.

1.2 A review of the developed Protection System settings.

1.3 Provide new or revised Protection System settings to the Planning Coordinator, Reliability Coordinator, and Balancing Authority.

1.3.1 Respond to the Planning Coordinator or Reliability Coordinator's comments regarding the proposed new or revised Protection System settings.

1.4 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.4.1 Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

Also, to clarify and reinforce the nature of the broader protection coordination concern, the following modification to the Purpose is proposed:

“To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults without causing an inadvertent adverse impact anywhere on the BES.”

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter

Pamela Hunter

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

SERC

Selected Answer:

Answer Comment:

We request that the SDT consider the following changes/ clarifications:

Present language:

R1.1 A review and update of short-circuit models for the BES Elements under study.

Proposed:

R1.1 A review and update of short-circuit models or data for the BES Elements under study.

This change will address concerns from GOs and DPs that don't have anything to do with the short-circuit model and potentially only need the fault current data at the interconnected bus from the TO.

In the rational box for **R2:**

Present language:

The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators.

Proposed language:

The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators or Transmission Owners.

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Selected Answer:

Answer Comment:

SCL General Comments

1) The Option 2 baseline should include a system-wide review of the entities instantaneous overcurrent elements, that are utilized on the BES, as well as the performance of the baseline fault study.

SCL experience has demonstrated that overreaching instantaneous overcurrent elements are one of the largest causes of miscoordination in a Protective Relay System.

2) The draft Standard, in its present form, is reminiscent of the early stages of the PRC-005 (Relay Maintenance) Standard, in that each utility will establish their own implementation (issue and installation of the relay settings) schedule timeline, without any constraints. This did not work well, for Standard PRC-005 as the utilities with strong maintenance plans were scrutinized, during audits, much more rigorously than those utilities with weaker maintenance plans, even though the weaker maintenance plans made the BES less reliable. It required several revisions of the PRC-005 Standard to get everyone on the same playing field. SCL believes that a similar situation will occur if a not-to-exceed schedule timeline is not established for the implementation of the revised relay settings.

R1. - Introduction

Modify text in paragraph to read: such that the Protection Systems, associated with the protective functions listed in Attachment A, operate in the intended sequence during faults.

R1. – Add Section 1.4

Inside of this section describe the timeline allowed to implement the revised relay settings.

For example, “new and revised relay settings necessary for the coordination of the Protection Systems, associated with the protective functions listed in Attachment A, shall be issued and installed within one year after the Protection Coordination Study has been performed”.

R2. – Option 2

Modify text in paragraph to include the following steps:

1) Compare the present fault current values to the previously established fault current baseline at each BES bus within the entitiy's system, with Protection Systems, associated with the protective functions listed in Attachment A.

2) Identify the buses where the present fault current value exceeds the baseline value by an amount that is 15%, or greater, in magnitude.

3) Perform a Protection System Coordination Study on the area of the system defined by the BES elements that are connected to the buses identified in Step 2.

4) The time interval to perform steps 1-3 shall not exceed six calendar years.

ATTACHMENT A

Modify text for relay elements as follows (line number defined at beginning of sentence):

21-1 – Zone 1 distance relay if:

• Infeed is used in determining reach (phase & ground distance), or

• zero-sequence mutual coupling is used in determining reach (ground distance)

21-2 – Zone 2 distance relay if:

• Infeed is used in determining reach (phase & ground distance), or

• zero-sequence mutual coupling is used in determining reach (ground distance)

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent if used in a non-communication-assisted protection scheme.

67 I – Directional Instantaneous overcurrent

67 T – Directional inverse time overcurrent if used in a non-communication-assisted protection scheme.

SUPPLEMENTAL MATERIAL REQUIREMENTS R1

Modify the text for the last paragraph of Section R1 just above Part 1.1 to read:

The coordination of some Protections Systems may seem unnecessary, such as for a line element that is protected solely by dual current differential relays . . . with other Protection Systems of the line element such that tripping does not unnecessarily occur for faults outside of the differential zone, unless there is a Protection System failure on the adjacent line element.

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Please state that when a fault current baseline is first established we are not required to show a coordination study for every protection scheme on our system. Please state that utilities are not required to show a coordination study if the baseline continues to show a fault current change less than 15%?

Requirement R2 option 2 states “Fault current values (either three phase or phase to ground) at a bus to which the Element is connected” where the RSAW states “Fault current comparison and results for each BES Element”. The RSAW and Standard should match language as closely as possible. In this case the standard states bus faults and the RSAW evidence specifies each element which is more than just a bus. It may be wise to delay industry RSAW reviews until the standard language is in a more finalized state.

Consider adding a modification to R2. There should be an allowed time line for a coordination study to take place after the 15% fault current threshold has been identified as being exceeded. This presents a risk many could step into unwittingly when the identification is close to the 6 year interval. There are circumstances where fault currents may not change until close to this 6 year interval due to system changes that may not be foreseen. We suggest the requirement include a two year window after a 15% change is identified.

Please provide a definition or examples to clarify what is considered “electrically-joined Facilities”. For example, if a line and both terminals and protection is owned by entity A at sub 1 and sub 2. All other equipment at sub 1 is owned by entity B. All equipment at Sub 2 is owned by entity A. Is sub 2 “electrically-joined”?

The RSAW in the sections for R1 and R3 states: “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation”. We request a provision in the Standard allowing if all separate functional entities within an organization have access to the same internal documentation, then the communication aspects are not required.

In a situation where utility A does work for another utility B on their transmission system protection equipment and utility A owns all the other surrounding protection systems, please clarify how the communication evidence would change with coordination work since utility A is making all the coordination decisions. Is it acceptable to show utility A has all utility B protection system settings internally stored? Does this make utility A responsible for utility B compliance?

For a facility that has multiple bus voltages such as 115kV, 230kV and 345kV and if the fault current baseline exceeds 15% on just the 115kV bus does this mean just the elements connected to the 115kV bus must have a coordination study but not the 230 or 345kV buses?

Document Name:

Likes: 1 Nebraska Public Power District, 1, Cawley Jamison
Nebraska Public Power District, 1, Cawley Jamiso

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter	Segment
Ginette Lacasse	1,3,4,5,6
Entity	**Region(s)**
Seattle City Light	WECC

Selected Answer:

Answer Comment:

SCL GENERAL COMMENTS

1) The Option 2 baseline should include a system-wide review of the entities instantaneous overcurrent elements, that are utilized on the BES, as well as the performance of the baseline fault study.

SCL experience has demonstrated that overreaching instantaneous overcurrent elements are one of the largest causes of miscoordination in a Protective Relay System.

2) The draft Standard, in its present form, is reminiscent of the early stages of the PRC-005 (Relay Maintenance) Standard, in that each utility will establish their own implementation (issue and installation of the relay settings) schedule timeline, without any constraints. This did not work well, for Standard PRC-005 as the utilities with strong maintenance plans were scrutinized, during audits,

much more rigorously than those utilities with weaker maintenance plans, even though the weaker maintenance plans made the BES less reliable. It required several revisions of the PRC-005 Standard to get everyone on the same playing field. SCL believes that a similar situation will occur if a not-to-exceed schedule timeline is not established for the implementation of the revised relay settings.

R1. - Introduction

Modify text in paragraph to read: such that the Protection Systems, associated with the protective functions listed in Attachment A, operate in the intended sequence during faults.

R1. – Add Section 1.4

Inside of this section describe the timeline allowed to implement the revised relay settings.

For example, "new and revised relay settings necessary for the coordination of the Protection Systems, associated with the protective functions listed in Attachment A, shall be issued and installed within one year after the Protection Coordination Study has been performed".

R2. – Option 2

Modify text in paragraph to include the following steps:

1) Compare the present fault current values to the previously established fault current baseline at each BES bus within the entitiy's system, with Protection Systems, associated with the protective functions listed in Attachment A.

2) Identify the buses where the present fault current value exceeds the baseline value by an amount that is 15%, or greater, in magnitude.

3) Perform a Protection System Coordination Study on the area of the system defined by the BES elements that are connected to the buses identified in Step 2.

4) The time interval to perform steps 1-3 shall not exceed six calendar years.

ATTACHMENT A

Modify text for relay elements as follows (line number defined at beginning of sentence):

21-1 – Zone 1 distance relay if:

•   Infeed is used in determining reach (phase & ground distance), or

•   zero-sequence mutual coupling is used in determining reach (ground distance)

21-2 – Zone 2 distance relay if:

•   Infeed is used in determining reach (phase & ground distance), or

•   zero-sequence mutual coupling is used in determining reach (ground distance)

50 –   Instantaneous overcurrent

51 –   AC inverse time overcurrent if used in a non-communication-assisted protection scheme.

67 I –   Directional Instantaneous overcurrent

67 T – Directional inverse time overcurrent if used in a non-communication-assisted protection scheme.

SUPPLEMENTAL MATERIAL REQUIREMENT R1

Modify the text for the last paragraph of Section R1 just above Part 1.1 to read:

The coordination of some Protections Systems may seem unnecessary, such as for a line element that is protected solely by dual current differential relays with other Protection Systems of the line element such that tripping does not unnecessarily occur for faults outside of the differential zone, unless there is a Protection System failure on the adjacent line element.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

ATC recommends revising PRC-027-1 to identify a clear connection between performance and the requirements of this standard. Where PRC-004 data provides a mechanism to measure performance, the better means to achieve reliability performance would allow each entity to use its company's misoperations data and the greater industry data to develop a program that addresses its greatest need.

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - PRC-027 Project

Group Member Name	Entity	Region	Segments
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Voter Information

Voter

Ben Engelby

Segment

6

Entity

ACES Power Marketing

Region(s)

Selected Answer:

Answer Comment:

1. For requirement R1, Part 1.1, the requirement states that the TO, GO, and DP must have a process to review and update short-circuit models for BES Elements under study. We disagree that the GO and DP must complete their own short-circuit models. Our recommendation is to allow GOs and DPs to use the TO’s short circuit study for applicable GO or DP buses.
2. For requirement R1, Part 1.3, we disagree with the requirement of documenting internal coordination, especially considering that smaller

entities may have a single protection engineer that is responsible for completing the study. Also, we disagree that there needs to be eight sub-parts for joint ownership coordination. This is administrative in nature and burdensome for compliance. This sub-part is overly complicated and creates opportunities for entities to fall out of compliance. There is little benefit to reliability for having this much detail required.

3. For requirement R2, option 1, performing studies for all applicable relays can be resource intensive, especially for smaller entities. We recommend that the drafting team consider the Cost Effective Analysis Process (CEAP) to determine if the reliability benefits outweigh the cost of compliance.
4. For requirement R2, option 2, the baseline process is complicated. We recommend stating in footnote one that the baseline for option 2 must be completed within 12 months after the standard goes into effect. Also, the measure should state that if there is not a fault current deviation greater than 15 percent, then an attestation is sufficient evidence for compliance.
5. For requirement R2, option 3, there should be specific guidance in the measures to demonstrate compliance for the combined approach, such as a baseline for applicable distance or overcurrent relays to occur within 12 months of the effective date and a Protection System Coordination Study (PSCS) for the remaining applicable Protection Systems to occur every 6 years after the effective date.
6. For requirement R3, the documentation requirements for coordination activities of new/revised settings is administrative in nature. We question the need for an administrative documentation requirement that is assessed a high risk. Industry has long history of coordinating Protection Systems and there is not any evidence of a widespread lack of Protection System coordination. We do not see how requiring a documented process will reduce the risks to reliability. Thus, we do not see how it enhances reliability and believe it could actually detract by causing applicable entities to focus on paperwork.

Document Name:

Likes: 0

Dislikes: 0

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4 -

Selected Answer:

Answer Comment:

FE's primary concern relates to what is required of the GO to be able to comply with R1 which states the TO, GO and DP "… establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults." The GO, operates the units essentially as isolated BES elements. The term "sequence" infers it is referring to the BES as a whole, at least with regard to interconnected elements, which would then mean we need a joint process with the TO. The GO is not in a position to make that happen, nor should the GO have primary responsibility. This should be a TO responsibility, with GO providing settings as requested by TO, and GO changing settings as requested/instructed by the TO.

FE believes the TO should be identified as the entity to establish the system protection coordination and be responsible for PSCSs (Power System Coordination Studies), Fault Studies, Short Circuit Studies, etc., to prove coordination. Communication to the GO should also be the TO's responsibility. The GO would be responsible to implement setting changes as directed by the TO, where applicable and if able. The GO's connection to the BES normally ends/terminates with the Generator Step Up transformer so the GO does not have the data to perform any Power System Coordination Studies, Fault Studies, or Short Circuit Studies

Document Name:

Likes: 0

Dislikes: 0

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: "To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those Faults, such that the Protection Systems operate in the intended sequence during Faults." PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii).

Completed Actions	Date
Standard Authorization Request (SAR) posted for comment	June 11 – July 10, 2007
SAR approved	August 13, 2007
Draft 1 of PRC-001-2 posted for comment	September 11 – October 26, 2009
Draft 1 of PRC-027-1 posted for formal comment with ballot	May 21 – July 5, 2012
Draft 2 of PRC-027-1 posted for formal comment with ballot	November 16 – December 17, 2012
Draft 3 of PRC-027-1 posted for formal comment with ballot	June 4 – July 3, 2013
Draft 4 of PRC-027-1 posted for formal comment with ballot	November 4 – December 31, 2013
Draft 5 of PRC-027-1 posted for informal comment	October 1 – October 21, 2014
Draft 5 of PRC-027-1 posted for formal comment with ballot	April 1 – May 15, 2015
Draft 6 of PRC-027-1 posted for formal comment with ballot	July 29 – September 11, 2015

Anticipated Actions	Date
10-day final ballot	October, 2015
NERC Board of Trustees (BOT) adoption	November, 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Protection System Coordination Study

An analysis to determine whether Protection Systems for BES Elements [JS1]operate in the intended sequence during Faults.

Protection System Issues Addressed by Other Reliability Standards:

Fault clearing is the only aspect of protection coordination addressed by Reliability Standard PRC-027-1. Including aspects of protection coordination other than Fault coordination would cause duplication or conflict with the requirements of other Reliability Standards. Specifically, other protection issues, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following Reliability Standards:

- Underfrequency Load shedding programs are addressed in PRC-006-2.
- Undervoltage Load shedding programs are addressed in PRC-010-1.
- Generator performance during declined frequency and voltage excursions is addressed in PRC-024-1.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-1.
- Transmission relay loadability is addressed in PRC-023-3.
- Generator relay loadability is addressed in PRC-025-1.
- Protective relay response during stable power swings is addressed in PRC-026-1.
- Protection System Misoperations (including those caused by coordination issues) are addressed in PRC-004-3.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title: Coordination of Protection Systems for Performance During Faults**
2. **Number:** PRC-027-1
3. **Purpose:** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Owner
   4.1.2. Generator Owner
   4.1.3. Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 below)
   ~~**4.1.3.**~~**4.1.4.** Transmission Planner

   4.2. Facilities: Protection Systems installed to detect and isolate Faults on BES Elements.

5. **Effective Date:** See the Implementation Plan for PRC-027-1, Project 2007-06 System Protection Coordination.

B. Requirements and Measures

Rationale for Requirement R1:[JS2]

Coordinated Protection Systems enhance reliability by isolating faulted equipment, thus reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. The stated purpose of this standard is: “To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those Faults, such that the Protection Systems operate in the intended sequence during Faults.” Requirement R1 captures this intent by requiring responsible entities establish a process that, when followed, allows for their Protection Systems to operate in the intended sequence during Faults. Requirement R1, Parts 1.1 through 1.3 are key elements to the process for developing Protection System settings.

Part 1.1 Reviewing and updating the short-circuit models used to develop new or revised Protection System settings helps to assure that settings are developed using accurate, up-to-date information.

Part 1.2 A review of the developed Protection System settings reduces the likelihood of introducing human error and verifies that the settings produced meet the technical criteria of the entity. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of reviews.

Part 1.3 The coordination of Protection Systems associated with BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) is essential to the reliability of the BES. Communication and review of proposed settings among these entities are necessary to identify potential coordination issues and address the issues prior to implementation of any proposed Protection System changes.

Unforeseen circumstances could require immediate changes to Protection System settings. Requirement R1, Part 1.3.4 requires owners to include a procedure to communicate those unplanned settings changes after-the-fact to the other owner(s) of the electrically-joined Facilities.

Note: In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for ~~developing new and revised~~performing a Protection System Coordination Study ~~settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults~~[JS3]. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~1.1. A review and update of short-circuit models for the BES Elements under study.~~[JS4]

~~1.2.~~1.1. ~~A~~ Its method to review ~~of the~~its developed Protection System settings before they are applied.

~~1.3.~~1.2. For its settings for Protection Systems ~~settings applied on~~for [JS5]BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

~~1.3.1.~~1.2.1. Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

~~1.3.2.~~1.2.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

~~1.3.3.~~1.2.3. Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

~~1.3.4.~~1.2.4. Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:

~~1.3.4.1.~~1.2.4.1. Implementation or commissioning.

~~1.3.4.2.~~1.2.4.2. Misoperation investigations.

~~1.3.4.3.~~1.2.4.3. Maintenance activities.

~~1.3.4.4.~~1.2.4.4. Emergency replacements required as a result of Protection System component failure.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity established a process to ~~develop settings for its~~perform a Protection System~~s~~ Coordination Study, in accordance with Requirement R1.

Rationale for Requirement R2:

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities (Transmission Owners, Generator Owners, and Distribution Providers) to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. The numerical identifiers in Attachment A represent general protective device functions per ANSI/IEEE *Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Requirement R2 provides responsible entities with options to assess the state of their Protection System coordination.

Option 1 is a time-based methodology. The entity may choose to perform, at least once every six years, a Protection System Coordination Study for each of its BES Protection Systems identified as being affected by changes in Fault current. The six calendar year time interval was selected as a balance between the resources required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

Option 2 is a Fault current based methodology. If Option 2 is initially selected, Fault current baseline(s) must be established prior to the effective date of this Reliability Standard. A baseline may be established when a new Element is installed or after a Protection System Coordination Study has been performed. The baseline(s) will be used as control point(s) for future Fault current comparisons. The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators. At least once every six calendar years following the effective date of this standard, the entity will perform a Protection System Coordination Study when its Fault current comparison identifies a 15 percent or greater deviation in Fault current values (either three-phase or phase-to-ground) at each bus to which the Element is connected.

The baseline Fault current value(s) will be re-established whenever a new Protection System Coordination Study is performed. Fault current changes on the System not directly associated with BES modifications are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection System functions (identified in Attachment A of this standard) during Fault conditions. A Fault current deviation threshold of 15 percent or greater (as compared to the established baseline) and a maximum time interval of six calendar years were chosen for these evaluations. These parameters provide an entity with latitude to choose a Fault current threshold and time interval that best match its protection philosophy, Protection System maintenance schedule, or other business considerations, without creating risk to reliability (See the Supplemental Material section for more detailed discussion).

The footnote in Option 2 describes how an entity may change from a time-based option to a Fault current based option for existing Elements when performing Protection System Coordination Studies. The footnote also allows for the creation of a baseline when a Protection System Coordination Study is performed for installing new Elements.

Option 3 provides the entity the choice of using both the time-based and Fault current based methodologies. For example, the entity may choose to utilize the time-based methodology for Protection Systems at more critical Facilities and use the Fault current based methodology for Protection Systems at other Facilities.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater ~~deviation~~ increase[JS6] in Fault current values (for either three-phase or phase-to-ground Faults) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years;~~[1]~~[JS7] or,
- Option 3: A combination of the above.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity performed Protection System Coordination Study(ies) and/or Fault current comparisons in accordance with Requirement R2.

~~[1] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline by performing a Protection System Coordination Study.~~

Rationale for Requirement R3:

Utilizing the processes established in Requirement R1 to develop new and revised Protection System settings provides a consistent approach to the development of Protection System settings and will minimize the potential for errors.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 and one of the options in Requirement R2[JS8] to develop its new and revised settings for Protection System ~~settings~~ for BES Elements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity utilized its settings development process established in Requirement R1, as specified in Requirement R3.

Rationale for Requirement R4:

Transmission Planners develop short circuit data bases per MOD-032-1 and utilize them in TPL-001-4 to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt. Since Transmission Planners develop and use short circuit databases, having other entities (TOs, GOs and DPs) use them could introduce errors. Therefore, Transmission Planners are required to calculate all Fault current values (an initial baseline and subsequent periodic updates) and make those available to its Transmission Owners, Generator Owners, and Distribution Providers.

R4. Each Transmission Planner shall calculate the baseline Fault currents for both three-phase and phase-to-ground Faults for all its busses and make such results available its Transmission Owners, Generator Owners, and Distribution Providers. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Each Transmission Planner shall annually update the Fault currents for all its busses and make such updates available its Transmission Owners, Generator Owners, and Distribution Providers.

4.1.1. For new busses, the Fault currents initially calculated for that bus shall become its baseline Fault currents.

4.1.2. The Transmission Planner shall reset the baseline Fault currents for any bus when a Fault current (for either a three-phase or phase-to-ground Fault) is greater than or equal to 1.15 times the previously established Fault current baseline has been calculated for that bus.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that each Transmission Planner made available its initial baseline and its annual updates of Fault current values for all its busses to its

Transmission Owners, Generation Owners, and Distribution Planners, and that it has reset the baseline Fault currents at busses in accordance with part 4.1.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance with Requirements R1, R2, and R3, and Measures M1, M2, and M3 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 or Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.3. OR The responsible entity failed to establish any process in accordance with Requirement R1.
R2.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3 but was late by less than or equal to 30 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 90 calendar days. OR The responsible entity failed to perform Option 1, Option

				2, or Option 3, in accordance with Requirement R2.
R3.	N/A	N/A	N/A	The responsible entity failed to utilize the process established in accordance with Requirement R1.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee – "Power Plant and Transmission System Protection Coordination."

NERC System Protection and Control Task Force, December 7, 2006, "Assessment of Standard PRC-001-0 – System Protection Coordination."

NERC System Protection and Control Task Force, September 2006, "The Complexity of Protecting Three-Terminal Transmission Lines."

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	New standard developed under Project 2007-06

Attachment A

The following Protection System functions[2] are applicable to Requirement R2 if available Fault current levels are used to develop the settings for those Protection System functions:

21 – Distance if:

- infeed is used in determining reach (phase and ground distance), or
- zero-sequence mutual coupling is used in determining reach (ground distance).

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent

67 – AC directional overcurrent if used in a non-communication-aided protection scheme

Notes:

1. The above Protection System functions are susceptible to changes in the magnitude of available short-circuit Fault current. These functions utilize current in their measurement to initiate tripping of circuit breakers. The functions listed above are included in a Protection System Coordination Study because they require coordination with other Protection Systems.
2. See the PRC-027-1 Supplemental Material section for additional information.

[2] ANSI/IEEE Standard C37.2 *Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Purpose

The Purpose states: To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.

Coordinated Protection Systems enhance reliability by isolating faulted equipment, reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. This standard requires that entities establish and implement a process to coordinate their BES Protection Systems to operate in the intended sequence during Faults.

Applicability

Transmission Owners, Generator Owners, and Distribution Providers are included in the Applicability of PRC-027-1 because they may own Protection Systems that are installed for the purpose of detecting Faults on the Bulk Electric System (BES). It is only those Protection Systems that are under the purview of this standard.

Transmission Owners are included in the Applicability of PRC-027-1 because they own the largest number of Protection Systems installed for the purpose of detecting Faults on the BES.

Generator Owners have Protection Systems installed for the purpose of detecting Faults on the BES. It is important that those Protection Systems are coordinated with Protection Systems owned by Transmission Owners to ensure that generation Facilities do not become disconnected from the BES unnecessarily. Functions such as impedance reaches, overcurrent pickups, and time delays need to be evaluated for coordination.

A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.

After the Protection Systems of Distribution Providers and Generator Owners are shown to be coordinated with other Protection Systems on the BES, there will be little future impact on the entities unless there are significant changes at or near the bus that interconnects with the Transmission Owner. The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current availability upon request by the Distribution Provider or Generator Owner. The Distribution Provider and Generator Owner will determine whether a change in Fault current from the baseline has occurred such that a review of coordination is necessary.

Requirement R1

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults.

The reliability objective of this requirement is to have applicable entities establish a process to develop settings for coordinating their BES Protection Systems, such that they operate in the intended sequence during Faults. The parts that are included as elements of the process ensure the development of accurate settings, as well as providing internal and external checks to minimize the possibility of errors that could be introduced in the development of settings.

This standard references various publications that discuss protective relaying theory and application. The description of "coordination of protection" is from the IEEE Standard C37.113-1999 (Reaffirmed: 2004), *Guide for Protective Relay Applications to Transmission Lines*, which reads:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Entities may have differing technical criteria for the development of Protection System settings based on their own philosophies. These philosophies can vary based on system topology, protection technology utilized, as well as historical knowledge; as such, a single definition or criterion for "Protection System coordination" is not practical.

The coordination of some Protection Systems may seem unnecessary, such as for a line that is protected solely by dual current differential relays. However, backup Protection Systems that are enabled to operate based on current or apparent impedance with some definite or inverse time delay must be coordinated with other Protection Systems of the Element such that tripping does not unnecessarily occur for Faults outside of the differential zone.

Part 1.1 A review and update of short-circuit models for the BES Elements under study.

The study used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers is the short-circuit study. Including a review and, if necessary, an update of short-circuit study information is necessary to ensure that information accurately reflects the physical power system that will form the basis of the Protection System Coordination Study and development of Protection System relay settings. The results of a short-circuit study are only as accurate as the information that its calculations are based on.

A short-circuit study is an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical Fault. Because the results of short-circuit studies are used as the basis for protective device coordination studies, the short-circuit model should accurately reflect the physical power system.

Reviews could include:

1. A review of applicable BES line, transformer, and generator impedances.

2. A review of the network model to confirm the network in the study accurately reflects the configuration of the actual System, or how the System will be configured when the proposed relay settings are installed.
3. A review, where applicable, of interconnected Transmission Owner, Generator Owner, and Distribution Provider information.

Part 1.2 A review of the developed Protection System settings.

A review of the Protection System settings prior to implementation reduces the possibility of introducing human error. A review is any systematic process of verifying the developed settings meet the technical criteria of the entity. Examples of reviews include peer reviews, automated checking programs, and entity-developed review procedures.

Part 1.3 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

Requirement R1, Part 1.3 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities. Communication among these entities is essential so potential Protection System coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

Part 1.3.1 1.3.1. Provide the proposed Protection System settings to the owners of the electrically-joined Facilities.

Requirement R1, Part 1.3.1 requires the entity to include in its process a provision to provide proposed Protection System settings to other entities. This communication ensures that the other entities have the necessary information to review the settings and determine if there are any Protection System coordination issues.

Part 1.3.2 Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

Requirement R1, Part 1.3.2 requires the entity receiving proposed Protection System settings to include in its process a provision to respond to the entity that initiated the proposed changes. This ensures that the proposed settings are reviewed and that the initiating entity receives a response indicating Protection System coordination issues were identified, or affirmation that no issues were identified.

Part 1.3.3 Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Requirement R1, Part 1.3.3 requires the entity to include in their process a provision to verify that any identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation. This ensures that any potential impact to BES reliability is minimized.

Note: There could be instances where coordination issues are identified and the entities agree not to mitigate all of the issues based on engineering judgement. It is also recognized that coordination issues identified during a project may not be immediately resolved if the resolution involves additional system modifications not identified in the initial project scope. Further, there could be situations where protection philosophies differ between entities, but the entities can agree that these differences do not create coordination issues.

Part 1.3.4 Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:

1.3.4.1. Implementation or commissioning.

1.3.4.2. Misoperation investigations.

1.3.4.3. Maintenance activities.

1.3.4.4. Emergency replacements required as a result of Protection System component failure.

Requirement R1, Part 1.3.4 requires the entity to communicate revisions to Protection System settings that occur due to unforeseen circumstances and differ from those developed during the planning stages of projects.

Requirement R2

This requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A:

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years;[3] or,
- Option 3: A combination of the above.

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. Two triggers were established for initiating a review of existing Protection System settings to allow for industry flexibility.

[3] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline by performing a Protection System Coordination Study.

In the first option, an entity may choose a time-based methodology to review Protection System settings, thus eliminating the necessity of establishing a Fault current baseline and periodically performing Fault current comparisons. This option provides the entity the flexibility to choose an interval of up to six calendar years for performing the Protection System Coordination Studies for those Protection System functions in Attachment A. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which an Element is connected. This option allows the entity to choose an interval of up to six calendar years to perform the Fault current comparisons and Protection System Coordination Studies. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. A maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) was established based on generally-accepted margins for setting Protection Systems in which incremental Fault current changes would not interfere with coordination. The 15 percent maximum deviation provides an entity with latitude to choose a Fault current threshold that best matches its protection philosophy, or other business considerations. The Fault current based option requires an entity to first establish a Fault current baseline to be used as a point of reference for future Fault current studies. The Fault current values used in the percent change calculation, whether three-phase or phase-to-ground Fault currents, are typically determined with all generation in service and all transmission BES Elements in their normal operating state.

An entity that elects to use Option 2 following the effective date of the standard, must establish its baseline prior to the effective date. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline upon performing a Protection System Coordination Study. The Fault current values used in the original baseline can be updated or created when a Protection System Coordination Study is performed. The baseline values at each bus to which an Element is connected are updated whenever a new Protection System Coordination Study is performed for the subject Protection System.

> **Example:** An initial baseline is established at 10,000 amps. During the first short-circuit review, it is discovered that Fault current has increased to 11,250 amps (12.5 percent change); consequently, no Protection System Coordination Study is required since the increase is below the maximum 15 percent deviation. The baseline value for the next study remains at 10,000 amps because no study was performed. However, during the next Fault current comparison, the Fault current has increased to 11,500 (15 percent change); therefore, a Protection System Coordination Study is required, and a new baseline of 11,500 amps would be established.

> **Note:** In the first review described above, if the entity decides to perform a Protection System Coordination Study at the 12.5 percent deviation and the results of the study indicate that the settings still meet the setting criteria of the entity, then no settings changes are required and the baseline Fault current(s) would be updated.

As a third option, an entity has the flexibility to apply a combination of the two methodologies. For example, an entity may choose the periodic Protection System review (Option 1) and review its Facilities operated above 300 kV on a six year interval, while choosing to use the Fault current comparison (Option 2) for its Facilities operated below 300 kV.

Attachment A identifies the Protection System functions susceptible to changes in the magnitude of available short-circuit Fault current. These functions utilize AC current in their measurement to initiate tripping of circuit breakers. The numerical identifiers in Attachment A represent general device functions according to *ANSI/IEEE Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*. The device functions listed in Attachment A are to be reviewed provided they require coordination with other Protection Systems. The following scenarios provide some examples for applying Attachment A.

A "51 – AC inverse time overcurrent" relay connected to a CT on the neutral of a generator step-up transformer, referred to as "51N – AC Inverse Time Earth Overcurrent Relay (Neutral CT Method)" in ANSI/IEEE Standard C37.2, would be included in a Protection System Coordination Study. Also applicable, are "51 – AC Inverse time overcurrent" relays connected to CTs on the phases of an autotransformer for through-fault protection. Overcurrent functions used in conjunction with other functions are to be reviewed as well. An example is a definite-time overcurrent function, which is a "50 – Instantaneous overcurrent" function used in conjunction with a "62 – Time-delay" function.

If the functions listed in Attachment A are used in conjunction with other functions, they would be included in a Protection System Coordination Study provided they require coordination with other Protection Systems. An example of this is a time-delayed "21 – Distance" function, which is a "21 – Distance" function with a "62 – Time-delay" function. Another example would be a definite-time overcurrent function, which is a "50 – Instantaneous overcurrent" function with a "62 – Time-delay" function. A "50 – Instantaneous overcurrent" function used for supervising a "21 – Distance" function would not be included in a Protection System Coordination Study as it does not require coordination with other Protection Systems.

Reviewing "21 – Distance" functions is limited to those applied for phase and ground distance where infeed is used in determining the phase or ground distance setting when zero-sequence mutual coupling is used in determining the setting. Where infeed is not used in determining the setting, "21 – Distance" functions would not be included in a Protection System Coordination Study, as the reach is not susceptible to changes in the magnitude of available short-circuit Fault current. Where infeed is used in determining the reach, coordination can be affected by changes in the magnitude of available short-circuit Fault current. Two examples where infeed may be used in determining the reach, are protection for a transmission line with a long tap and a three-terminal transmission line. Ground distance functions are influenced by zero-sequence mutual coupling. The ground distance measurement can appear to be greater than or less than the true distance to a Fault when there is zero-sequence mutual coupling. The influence of zero-sequence mutual coupling changes with the magnitude of available short-circuit current. Therefore, “21 – Distance” functions would be included in a Protection System Coordination Study, when zero-sequence mutual coupling is used in determining the setting.

Requirement R3

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

The reliability objective of this requirement is for applicable entities to utilize the process established in Requirement R1. Utilizing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, decreases the possibility of introducing errors, and increases the likelihood of maintaining a coordinated Protection System.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes will be moved to this section.

Question:
2. Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.

Possible Answers

Browse...
Max Size: 25MB

Consideration of Comments

Project Name: 2007-06 System Protection Coordination | PRC-027-1 & PRC-001-1.1(ii)

Comment Period Start Date: 7/29/2015

Comment Period End Date: 9/11/2015

Associated Ballot: 2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) AB 2 ST

There were 64 sets of responses, including comments from approximately 162 different people from approximately 112 different companies representing 10 of the 10 Industry Segments as shown on the following pages.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

The drafting team made grammatical edits and provided additional information in the Rationale boxes and Supplemental Material section of the draft standard. The following clarifying revisions to the balloted standard were also made:

Requirements

Requirement R1, Part 1.1

Changed from "A review and update of short-circuit models for the BES Elements under study." to "A review and update of short-circuit model data for the BES Elements under study."

Requirement R1, Part 1.3.4

Changed the format incorporating the subparts into the main body of Part 1.3.4. It now reads as follows:

"Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure."

Requirement R2

Option 2 and **Footnote:** Inserted "BES" as a modifier of Element.

Option 3: Inserted "Use" at the beginning to align formatting with options 1 and 2.

Footnote: Inserted the following to clarify where Fault current baselines can be established:

"The Fault current baseline for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA)."

Attachment A: Revised general language.

Implementation Plan

Effective Date of New or Revised Standards

Changed the implementation period of the standard from twelve (12) months to twenty-four (24) months to provide entities more time to establish the (1) Protection System settings development process, (2) Fault Current baselines, and (3) tracking tool(s) for Fault Current baseline changes and/or Protection System Coordination Studies.

Added section "**Initial Performance of Requirement R2"**

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with

Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Questions

1. **The term "entity-designated" and its associated footnote were removed and replaced by "Attachment A." Attachment A lists the Protection System functions applicable in the standard. Do you agree that Attachment A includes the Protection System functions that must be reviewed to maintain Protection System coordination when Fault current levels change? If not, please provide the basis for your disagreement and any proposed revisions.**

2. **Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.**

3. **If you have any other comments that you haven't already provided in response to the above questions, please provide them here.**

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

1. The term "entity-designated" and its associated footnote were removed and replaced by "Attachment A." Attachment A lists the Protection System functions applicable in the standard. Do you agree that Attachment A includes the Protection System functions that must be reviewed to maintain Protection System coordination when Fault current levels change? If not, please provide the basis for your disagreement and any proposed revisions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer: Yes

Eric Schwarzrock - Berkshire Hathaway - NV Energy - 5 -

Selected Answer: No

Answer Comment:

- Attachment A does not list bus differential protection as an applicable protection function. Bus protection designed using either overcurrent, percentage differential or high impedance differential protection use a sum of currents to detect a bus fault. In an ideal world an increase in fault current would not affect the differential relays, but there are situations where an increase in fault current can negatively affect the differential relays and affect the coordination between bus differential and line relays.

◦ Overcurrent and percentage differential relays are usually applied on busses where fault currents are low enough so that CT saturation does not occur. As fault currents increase, the chances of CT saturation increase which can cause false bus differential operations for external line faults.

◦ High impedance differential relay voltage settings are calculated based on the voltage that could be developed across the relay with a completely saturated CT. This voltage setting is calculated using the maximum external fault current. With increased fault currents, the voltage that could develop across the relay for a saturated CT could be higher than the voltage setting of the relay. This can also cause false bus differential operations for external line faults.

Bus differential relays should be added to Attachment A to ensure that proper coordination between bus differential relays and line relays for external faults.

Response: Thank you for your comment. The drafting team asserts your examples represent local relay setting issues, not coordination issues. Bus differential relays settings are not based on coordination with other relays.

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer: Yes

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer: Yes

Mark Kenny - Northeast Utilities - 3 -

Selected Answer: Yes

Answer Comment: We agree with the classification of specific protection system elements that require coordination. In addition, this will aid the compliance enforcement process.

Response: Thank you for your comment.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer: Yes

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer: Yes

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6

Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: Yes

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	**Entity**	**Region**	**Segments**
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5

Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer: Yes

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Jay Barnett - Exxon Mobil - 7 -

Selected Answer: Yes

Answer Comment:

While I agree that the functions listed are the ones that should be reviewed if fault current levels change, I disagree with using fault current as a trigger for a review *in all circumstances*. For those functions that do not require fault current or Protection System settings from other entities in order to ensure proper coordination, entities should be able to use equipment changes as a trigger for a coordination review. Equipment changes are already used as a trigger for other Reliability Standards and would allow for entities to have a single trigger for multiple Standards. This would add an additional, more cost effective option, while still ensuring Protection Systems on all BES Elements are coordinated. The SDT should include this as another option under Requirement 2 (see proposed revision below). A fault current trigger would remain for those functions that require fault current or Protection System settings from other entities in order to ensure proper coordination.

Proposed Revision:

R2. Each TO, GO, and DP shall, for each BES Element with Protection System functions identified in Attachment A:

Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or

Option 2: . Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years; or,

Option 3: For functions that do not require Fault current or Protection System settings from other entities to ensure proper coordination, perform a PSCS prior to the implementation of new or modified Protection System settings on associated BES Elements.

Option 4: A combination of the above.

Response: Thank you for your comment. An entity must use at least one of the options provided in Requirement R2 to satisfy the requirement but the standard does not preclude an entity from performing additional Protection System Coordination Studies (PSCS) based on triggers other than Fault current or from performing PSCS more frequently.

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Likes: 1 Tarantino Joe On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1, Ke

Dislikes: 0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer: Yes

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5 -

Selected Answer: Yes

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment: For the GO function, it would be helpful to include 51V-R and 51V-C as in scope relays in Attachment A. Also for GO, it would be helpful to note that 50/27 or 67 relays/protective functions used in generator inadvertent energization schemes are not in scope for PRC-027. Additionally, it's not clear if the 50 includes overcurrent elements used to supervise distance (21) elements.

Response: Thank you for your comment. Any variation of 51 time overcurrent relays are included in Attachment A. Unless the 50/27 and 67 Protection System functions are installed to detect and isolate Faults on BES Elements, the functions are not included in the Applicability of PRC-027. The Supplemental Material includes the following: A "50 – Instantaneous overcurrent" function used for supervising a "21 – Distance" function would not be included in a Protection System Coordination Study as it does not require coordination with other Protection Systems.

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: No

Answer Comment: Revision Requirement 1 allows us to develop a criteria for intended sequence which is good. Our only concern is if our criteria changes, there is no verbiage in the standard that allows for a phased implementation plan. One suggestion could be to give a 6 year cycle to be sure improvements are made will staying compliant to the proposed standard.

Response: Thank you for your comment. The process established in Requirement R1 is for developing new and revised Protection System settings for BES Elements. If an entity makes changes to its process, the entity will follow its new process to develop all future new or revised Protection System settings. There is no requirement that an entity retroactively implement its new process on previously developed Protection System settings.

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:	No
Answer Comment:	See Comments from ACES

Response: Please see the drafting team's responses to the referenced comments.

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:	Yes

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:	No
Answer Comment:	In Attachment A, it seems that 67 elements used in communication-aided protection schemes should be applicable. If a communication-aided protecton scheme is needed for coordination with remote backup (e.g., long line adjacent to a short line, perhaps), a check may

need to be performed that (for example) overreaching ground overcurrent pickups are still appropriate. Tacoma Power will not object to lowering the compliance risk by leaving these elements out of Attachment A, but Tacoma Power did want to bring this to the drafting team's attention.

In Attachment A, or in the Supplemental Material section, breaker failure fault detectors should be discussed. As with the 67 element, if a breaker failure fault detector is set too high in (for example) a ring bus, remote backup protection could operate instead of the local breaker failure. As with the 67 element, Tacoma Power will not object to lowering the compliance risk by leaving these elements out of Attachment A, but it probably should be at least discussed by the drafting team and documented somewhere to avoid confusion later when/after the standard becomes effective.

Response: Thank you for your comment. The protective functions listed in Attachment A are included based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. The drafting team contends that the 67 element used in an overreaching communication scheme is not directly used to isolate Faults on BES Elements. With regards to breaker failure fault detectors, the drafting team does not consider your example a coordination issue but instead a local relay setting issue. Breaker failure Fault detector settings are not based on coordination with other relays.

Glenn Pressler - CPS Energy - 1 -

Selected Answer: No

Answer Comment: Agree with the elements listed, but I question the wording regarding the 21 elements. It sounds as if an entity simply sets this element by

	just taking a percent of the Positive Sequence Line impedance, even when infeed or mutuals are present (ground only), then the entity would never need to check these elements. However, if another entity does use these factors in determining settings of these elements, then that entity would be required to periodically check the settings. This seems to give a greater degree of risk for compliance failure for the entity that applies a more thorough method of setting these elements while leaving no risk to the entity that uses a simpler, less thorough setting method. Generally believe entities should be required to verify through studies that these elements will only operate for their intended zone of protection whenever infeed or mutuals are present.

Response: Thank you for your comment. The drafting team recognizes that entities have different protection philosophies to develop 21 element settings. If an entity does not consider infeed and no zero-sequence mutual impedances are present, the coordination of 21 elements would not need to be reviewed on a periodic basis because the settings are not based on available Fault current.

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

David Greene - SERC - 10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments

Paul Nauert	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
David Greene	SERC staff	SERC	10

Selected Answer: Yes

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2

Jonathan Hayes	Southwest Power Pool Inc	SPP	2
Robert Gray	Board of Public Utilities of Kansas City, Kansas	SPP	3
Michael Jacobs	Camstex	NA - Not Applicable	NA - Not Applicable
stephanie Johnson	Westar Energy, Inc	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Answer Comment: We agree that the addition of Attachment A gives the industry guidance to some of the system functions and their applicable in this process especially, in reference to the calculation of the Fault current when conducting the Protection System Coordination Study (PSCS). Additionally, this helps the industry develop effective procedures that will increase the Reliability of the BES.

Response: Thank you for your comment.

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer: Yes

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2007-06 PRC-027-1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6

Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Selected Answer: Yes

Answer Comment:	We agree with the classification of specific Protection System components that require coordination. In addition, this will aid the compliance enforcement process. However, clarification is requested with regard to applicability of distance protection element. Does the standard apply to distance elements used solely for non-communication aided protection schemes (for example transfer trip, carrier systems) or for all distance element applications?

Response: Thank you for your comment. If infeed is not used in determining the settings of the 21 elements used in the communication-aided Protection System, then 21 elements would not be included in the Protection System Coordination Study because settings are not developed based on available Fault current. The Supplemental Material section provides additional information on this subject.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:	Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:	Yes

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3 Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:	No

Answer Comment: Hydro One Networks Inc. agrees with the NPCC on the classification of specific protection systems that would entail protection system coordination. However, Hydro One Networks Inc.. would like to ask for clarification within Attachment 1 whether distance (21) elements within communications aided protection schemes are subject to the requirements of this standard. This is because there were conflicting responses provided by the NERC SDT during the Q&A Session held on August 25th, and by NATF during the monthly meeting call on August 27th.

Response: Thank you for your comment. If infeed is not used in determining the settings of the 21 elements used in the communication-aided Protection System, then 21 elements would not be included in the Protection System Coordination Study because settings are not developed based on available Fault current. The Supplemental Material section provides additional information on this subject.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	**Entity**	**Region**	**Segments**
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1

Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment: Attachment A would be a good list of items that must be reviewed if Fault current levels are expected to always increase, but not for any Fault current level change.

Response: Thank you for your comment. The protective functions listed in Attachment A are included based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. The drafting team contends that the functions listed in Attachment A and only those functions require review when available Fault current levels increase or decrease.

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer:

Answer Comment: Abstain

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer: No

Answer Comment: Attachment A would be a good list of items that must be reviewed if Fault current levels are expected to always increase, but not for any Fault current level change.

Response: Thank you for your comment. The protective functions listed in Attachment A are included based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. The drafting team contends that the functions listed in Attachment A and only those functions require review when available Fault current levels increase or decrease.

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Selected Answer: Yes

Answer Comment: Note: CAISO is not a party to the submission of the comments below.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Selected Answer: No

Answer Comment: See Section 3 below

Response: Please see the drafting team's responses to the referenced comments.

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer: Yes

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: No

Answer Comment: See general comments in #3

Response: Please see the drafting team's responses to the referenced comments.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - PRC-027 Project

Group Member Name	Entity	Region	Segments
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Selected Answer: Yes

Answer Comment: 1. We agree with the removal of the term “entity-designated” and the addition of Attachment A to provide more clarity.

2. Note #2 in the attachment refers to additional details located in the

supplemental information section of the standard. Once the standard is approved by FERC, only the applicability section and the requirements (and attachments that are incorporated by reference) will be enforceable. If the drafting team acknowledges that additional details are necessary to fully explain the attachment, then those details should be added at this stage of the development process.

Response: Thank you for your comments. Note 2 does not indicate that additional details are necessary to understand Attachment A. Note 2 simply indicates that additional discussion is provided in the Supplemental Material section of the standard, just as additional discussion is provided for the requirements, etc.

2. Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment: yes

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer:

Answer Comment: Yes,

SCE&G agrees with the SERC PCS committee comments: "It is our understanding that the 6-year evaluation interval begins on the enforcement date, allowing up to 6 years to complete a full system analysis. However, with this not being explicitly stated in the technical basis or implementation plan, we would recommend including that distinction in some location. "

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System

Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment: Yes

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment: AEP does not believe that 12 months is adequate for the Implementation Plan, and recommends that it be increased to 24 months, which we believe is more reasonable. The GO often relies on the TO to provide short-circuit studies, which increases the time necessary to establish the initial baseline.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment: **The Implementation Plan should be extended to 24 months. As it stands now, entities only have 12 months after regulatory approvals to develop a process, establish Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review**

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Mark Kenny - Northeast Utilities - 3 -

Selected Answer:

Answer Comment: We strongly believe that 12 months is an inadequate amount of time for an entity to develop a formal documented process, establish a Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review. We recommend that the Implementation Plan should be extended to 24 months.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its

Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer:

Answer Comment: Regarding Implementation Plan: NIPSCO believes 12 month implementation plan is very challenging and inadequate. NIPSCO recommends 24 months for implementation plan to allow entities sufficient time to establish resources and derive processes.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6

Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Selected Answer:

Answer Comment: The Technical Basis or Implementation Plan does not include sufficient details describing the 6 year evaluation interval. It is our understanding that this 6 year evaluation interval begins on the enforcement date allowing up to 6 years for the system analysis to be completed but this is not specifically stated so we recommend additional reference details be included to explicitly describe the Implementation times.

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4

Mahmood Safi	Omaha Public Utility District	MRO	1,3,5, 6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5, 6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5, 6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5, 6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer:

Answer Comment: Yes

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	**Entity**	**Region**	**Segments**
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5

Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer:

Answer Comment: No. While not “per se” an Implementation Plan issue, R2 is unclear as to when the first Protection System Coordination Study must be performed for Attachment A devices under R2. See additional comments in #3 below.

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment: Yes.

1) For R2, if an entity decides to go with option 1, does it mean that the entity is not required to do a Protection System Coordination Study until 6 years from the effective date of the standard?

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Jay Barnett - Exxon Mobil - 7 -

Selected Answer:

Answer Comment: Agree.

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment: Salt River Project (SRP) has reviewed the Attachment A and has concerns with verifying a Fault Current baseline as required in R3. As this standard is written, this baseline must be created prior to the effective date of the standard. We strongly believe that 12 months is an inadequate amount of time to develop a formal documented process, establish a Fault Current baseline for thousands of relays, and establish a tracking tool for those Fault Current baseline changes and/or periodic review. We request that there be at least a 24 month implementation plan.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Likes: 1 Tarantino Joe On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1, Ke

Dislikes: 0

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5 -

Selected Answer:

Answer Comment: More detail is needed regarding the implementation plan dates for each of the requirements. Also, required dates for R2 should address Options 1 and 2 individually.

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment: No; it would be helpful if the Implementation Plan included information on what is required on the effective date of the standard. There is clarifying text on page 7 of the RSAW that states what is required by the effective date of the standard, this could be included in the Implementation Plan.

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment: We do not agree with the proposed implementation plan. For larger entiites with assets in all regions, a 12-month implementation is a challenge. 24-months would be more appropriate without taking on risk.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:

Answer Comment: No, See comments from ACES

Response: Please see the drafting team’s responses to the referenced comments.

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer:

Answer Comment: SMUD Supports Salt River Project comments.

Response: Please see the drafting team's responses to the referenced comments.

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:

Answer Comment: There are no possible answers listed on this question to choose from (see attached screenshot), however, ITC Holdings would select 'YES' as an answer to this question.

Response: Thank you for your support.

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment: It appears that, where Option 2 is selected, only the Fault current baselines need to be established prior to the effective date, not (necessarily) any Protection System Coordination Studies. Is this the drafting team's intention?

Where Option 1 is selected, what is the implementation timeframe?

Response: Thank you for your comment. Yes, when Option 2 is selected, only the Fault current baselines must be established prior to the effective date of the standard. Requirement R2, Option 1 states that a Protection System Coordination Study must be performed in a time interval not to exceed six-calendar years (of the effective date of the standard).

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment: yes, but no button.

Response: Thank you for your support.

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment: Yes

David Greene - SERC - 10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Paul Nauert	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
David Greene	SERC staff	SERC	10

Selected Answer:

Answer Comment: It is our understanding that the 6-year evaluation interval begins on the enforcement date, allowing up to 6 years to complete a full system analysis. However, with this not being explicitly stated in the technical basis or implementation plan, we would recommend including that distinction in some location.

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer:

Answer Comment:

Based on our concerns regarding R1, subpart 1.2, as outlined in question 3, Duke Energy cannot agree to the proposed Implementation Plan. If the standard were to be approved as written, the expectation to review the developed Protection System settings, depending on the level of detail expected for the review, would take a significant amount of time to achieve compliance. For larger entities, with a great deal of applicable relays, additional resources would most definitely be required, and time to acquire and train those resources would be necessary. We do not feel the 12 months is an adequate amount of time to achieve compliance with the standard as written.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Jonathan Hayes	Southwest Power Pool Inc	SPP	2
Robert Gray	Board of Public Utilities of Kansas City, Kansas	SPP	3
Michael Jacobs	Camstex	NA - Not Applicable	NA - Not Applicable
stephanie Johnson	Westar Energy, Inc	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Answer Comment: We agree with the proposed Implementation Plan. In our opinion, the footnote provides the industry a clear and concise objective pertaining to both projects and their dependence on the success of the proposed retirement of PRC-001-1-1 (ii).

Response: Thank you for your support.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2007-06 PRC-027-1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1

Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5

Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Selected Answer:

Answer Comment: Checked--No

As it stands now, entities will not have adequate time, within 12 months, to develop a process, establish Fault current baselines, and establish a tracking tool for Fault current baseline changes and/or periodic review. We recommend that the Implementation Plan be extended to 24 months.

We recommend the implementation plan include a statement clarifying the start date of the 6 year cycle that is described in Requirement R2. Is it the date the standard is effective, or the date the protection system was last reviewed prior to the effective date?

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

The date of the last Protection System review prior to the effective date of the standard is not relevant in considering the initial performance of Requirement R2. The six-year interval begins on the effective date of the standard. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment: Yes.

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment: Texas RE agrees with the proposed Implement Plan.

Response: Thank you for your support.

Kenn Backholm - Snohomish County PUD No. 1 - 6 -

Selected Answer:

Answer Comment: Public Utility District No. 1 of Snohomish County supports Salt River Project comments.

Response: Please see the drafting team's responses to the referenced comments.

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:

Answer Comment: Hydro One Networks Inc. does not agree with the Implementation Plan as it is unreasonable to implement a process and establish a fault current baseline within 12 months. Further, the Implementation Plan of 12 months borders on the Long-term Planning horizon in requirement R1 itself. The NERC definition of a Long-term Planning horizon is "a planning horizon of one year or longer". Therefore, Hydro One Networks Inc. agrees with the NPCC, and recommends that the Implementation Plan be extended from 12 months to 24 months.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer:

Answer Comment: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment: Texas RE agrees with the proposed Implementation Plan.

Response: Thank you for your support.

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer:

Answer Comment: Abstain

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment: Yes

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2

Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Selected Answer:

Answer Comment: **NO.**

The Implementation Plan should be extended to 24 months. As it stands now, entities only have 12 months after regulatory approvals to develop a process, establish Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5

John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer:

Answer Comment: Yes.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Selected Answer:

Answer Comment: SCL does not have issues with this aspect. However, other utilities have expressed a concern about needing more time so it may be worthwhile re-evaluating the scope for implementation plan.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment: Yes.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer:

Answer Comment: Yes we have no issues but we have heard others are concerned that they will need more time.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment: If a utility is in the position to leverage a tool such as CAPE or ASPEN to automate its settings review, then the proposed implementation plan seems feasible. If a utility does not have a software tool in place, then developing and tracking the settings review may require significant resources. This may actually detract from a utility's ability to create and review relay settings.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - PRC-027 Project

Group Member Name	Entity	Region	Segments
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Mike Brytowski	Great River Energy	MRO	1,3,5, 6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3

Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Selected Answer:

Answer Comment: We agree with the implementation plan that both standards (PRC-027-1 and TOP-009-1) must reach industry consensus before they are presented to the NERC Board for adoption.

Response: Thank you for your support. The standards may be presented to the NERC BOT separately but NERC will submit the petitions for PRC-027-1 and TOP-009-1 to FERC together, requesting the full retirement of PRC-001-1(ii).

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4 -

Selected Answer:

Answer Comment: yes

3. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment: none

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Answer Comment: Portland General Electric Company (PGE) thanks you for the opportunity to comment on this standard. PGE's System Protection group finds the proposed standard to be generally acceptable. We would, however, request that the drafting team review part 2 of PRC-023-3 Attachment A and consider exclusion of the relay elements listed in 2.1 from the requirement of PRC-027.

Response: Thank you for your comment. The drafting team reviewed PRC-023-3, Attachment A, and sees no reliability benefit in making your suggested change. Depending upon an entity's protection philosophy, the relay elements excluded by Part 2.1 of PRC-023-3 Attachment A may or may not meet the criteria for inclusion in Attachment A of PRC-027-1. The protective functions listed in Attachment A of PRC-027-1 are included based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. The drafting team contends that the functions listed in Attachment A and only those functions require review when available Fault current levels increase or decrease.

Eric Schwarzrock - Berkshire Hathaway - NV Energy - 5 -

Answer Comment: • Option 2 of R2 is meant to allow an entity to periodically check for a 15 percent of greater deviation in fault current. This option allows the entity to choose an interval of up to six calendar years to perform the fault current comparisons (this comes from the PRC-027-1 supplemental material). Option 2 is worded in a confusing manner so that the intent is not immediately clear without reading the supplemental material.

• Attachment A lists the protection system functions applicable to R2 including: 67 – AC directional overcurrent if used in a **non-communication-aided protection scheme**. This is probably ok if the fault current increases. If the fault current decreases, then any 67 relays used in a communication-aided protection scheme might not work correctly. If the 67 element were set to overreach the other end of the line for a POTT scheme (similar to using a zone 2 element in a POTT scheme) and the fault current decreased, it's possible that the 67 element might now see faults at a maximum distance less than the distance of the line. This would render the POTT scheme not as effective since the element used to trigger the scheme does not see the entire line.

Option 2 states that a protection coordination study should be performed when a 15 percent or greater deviation in fault current is identified. A 15 percent decrease in fault current should warrant a re-study of directional overcurrent elements used in communication aided protection scheme.

Response: Thank you for your comment. Option 2 of Requirement R2 requires that both the Fault current comparison and any resulting Protection System Coordination Study (from the identification of a 15% or greater deviation in Fault current) be performed within a maximum 6-calendar-year timeframe. The drafting team notes that the purpose of the Rationale boxes and Supplemental Material section is to provide additional guidance and rationale regarding the tenets of the basic requirements of the standard. Though the Rationale boxes move to the Supplemental Material section of the standard when it becomes effective, both of these informational pieces remain a permanent part of the standard for entities and auditors to reference. Further, the draft Reliability Standard Audit Worksheet (RSAW) for PRC-027-1 explains what evidence is required to demonstrate compliance with this requirement.

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer Comment:

SCE&G agrees with the SERC PCS committee comments: "

Comments:

1) page 4, Please revise the Purpose and Facilities to clarify the scope.

a) Purpose: "To maintain the coordination of Protection Systems installed to protect detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults."

b) Facilities: "Protection Systems installed to detect and isolate Faults on protect BES Elements."

Also see comment #3 below. There are a large number of DP-TO interfaces and clarity on this interface is needed.

2) page 6 Rationale Option 2: augment 'Planners and Planning Coordinators' with 'Transmission Owner' so it reads "The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Owners, Transmission Planners, or Planning Coordinators." This makes it consistent with R1 1.1 itself, page 14 explanation.

3) page 13 DP Applicability is explained by 'A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.' A) In the vast majority of cases fault current contributions from DP networks are quite

weak, usually the last to trip, and insignificant to BES coordination. B) BES Phase 2 Definition excluded networks below 50kV and at the least this should be acknowledged here. C) PRC-027-1 Draft 6 Applicability language is consistent with the PRC-005-2 language, for which PRC-005-2 Supplement states: "'…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).' The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System **protecting** that Element should then be included within this standard." D) Add language similar to B and C in the PRC-027-1 Supplemental Material.

4) page 17 second option: Please clarify the Fault current location for the 15% deviation trigger is the BES bus. This will help the GO and DP understand their responsibility. Please insert BES before Element in this sentence "The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which an a BES Element is connected. The drafting team intends for the 100kV or above BES bus to be the Fault current location."

Response: Thank you for your comment.

The drafting team contends that the acts described in the Purpose statement "…detect and isolate Faults on Bulk Electric System (BES) Elements…" are the same as providing protection for those Elements. The drafting team declines to make the suggested change. (a) The drafting team contends that the phrase provided in section 4.2. Facilities, "…detect and isolate Faults on Bulk Electric System (BES) Elements…" is the same as providing protection for those Elements. The drafting team declines to make the suggested change.

The drafting team contends that the phrase provided in section 4.2. Facilities, "…detect and isolate Faults on Bulk Electric System (BES) Elements…" is the same as providing protection for those Elements. The drafting team declines to make the suggested change.

The drafting team modified the Rationale box for Requirement R2 to include the Transmission Owner as you suggest.

Thank you for your comment. PRC-027-1 is consistent in its applicability to Protection Systems designed to detect (and isolate) Faults on BES Elements, and will, therefore follow with any definition of the Bulk Electric System as you suggest. Protection System Coordination is about isolating Faults in an intended sequence, not just about protecting Elements from Faults. PRC-027-1 will also follow with any definition of the Bulk Electric System.

The drafting team made the suggested change.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Answer Comment: n/a

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment: AEP supports R1 & R3. AEP believes it is reasonable to have a process to develop Protection System settings for all BES elements, and to implement that process. AEP is willing to accept the inclusion of all BES protection systems in these requirements.

AEP does not support R2 as written in draft 6. AEP believes R2 should be limited to protection systems applied on BES Elements that electrically join Facilities owned by separate functional entities. It is reasonable to require a periodic review, as prescribed in R2, on protection systems applied to interconnecting elements, because an entity does not have knowledge of what changes are made by another entity that may affect protection system coordination.

AEP believes that R1 is sufficient to cover coordination of all internal protection systems. AEP has an existing process to review area coordination when system changes are made. All settings in the area that are affected by the change are reviewed and revised as necessary. Because of this process, it is not likely that any fault current comparisons would identify a 15% deviation at any buses. Thus, this requirement would become an administrative burden without any reliability benefit for internal protection systems.

AEP proposes that R2 be changed to read:
R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) with Protection System functions identified in Attachment A:

While AEP is supportive of the overall intent and direction of PRC-027-1, we have chosen to vote negative driven by our objections to R2, as stated above.

Response: Thank you for your comment. The drafting team asserts it is difficult to support the position that having a procedure to develop settings alone will achieve the purpose of PRC-027-1: "To **maintain** the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults." The intent of Requirement R2 is to prevent existing Protection Systems (where no system modifications have occurred) from becoming uncoordinated due to incremental changes in Fault current that have occurred over time.

Likes:	0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Answer Comment: the HIGH VRF for Requirement R3 seems too high since failing to meet R1 (to develop the process for developing new and revised Protection System settings for BES Elements) has a MEDIUM VRF; failing to utilize this process should not have a VF that's higher than not having the process in place to begin with.

Response: Thank you for your comment. The drafting team modeled the VRFs for Requirements 1 and 3 after other FERC-approved NERC Reliability Standards. The VRFs for the requirements that required establishing or developing processes were lower VRFs than those requirements mandating the implementation or utilization of the processes. Please refer to the Violation Risk Factor and Violation Severity Level Justification Document for PRC-027-1.

Mark Kenny - Northeast Utilities - 3 -

Answer Comment:

1. We suggest that the drafting team consider the potential overlap of PRC-027-1 R1.1.1 and MOD-032-1, R1 and provide necessary clarification in the Supplemental Material.

2. R2, Option 2 has two actions associated with it, both of which have to be completed in one timeframe. The two actions are the fault current comparison against the baseline and the performance of a Protection System Coordination Study if the fault current comparison exceeds 15% or greater deviation. It is recommended that under this option, if an entity identifies a 15% or greater deviation in fault current value at a bus, the entity is given a set amount of time

	per element to complete a protection coordination study on all applicable elements at that bus.

Response: Thank you for your comments.

There is no overlap or conflict between PRC-027-1 Requirement R1, Part 1.1 and MOD-032-1, Requirement R1. Requirement R1 Part 1.1 of PRC-027-1 ensures that the short-circuit model data is reviewed for accuracy before being used to develop new or revised Protection System settings.

Option 2 of Requirement R2 is a Fault current based methodology for determining when a PSCS must be performed for Protection System functions listed in Attachment A. The second action you mention (performing a Protection System Coordination Study) is only required when a 15% or greater deviation from the established baseline fault current at the bus to which the Element is connected is identified. An entity can judiciously select the interval that a comparison of present Fault current values to an established Fault current baseline is made; thereby allowing adequate time after the identification of the Fault current deviation to perform the Protection System Coordination Study.

Anthony Jablonski - ReliabilityFirst - 10 -

Answer Comment:	**ReliabilityFirst agrees that PRC-027-1 helps to alleviate the risk of insufficient coordination of Protection Systems installed to detect Faults on BES Elements and isolate those faulted Elements (such that the Protection Systems operate in the intended sequence during Faults). ReliabilityFirst offers the following comments related to the term "coordination" for the Standard Drafting Team's consideration**: 1. **ReliabilityFirst notes that the term "coordination" used in Requirement 1, Parts 1.3.2 and 1.3.3 is not defined within PRC-027-1 or the NERC Glossary Terms. This term is also used within a number of other Reliability Standards**

where it is likewise undefined. As a result, and according to FERC precedent, the dictionary definition of the term "coordination" will control. As a result, the term "coordination" could reasonably be interpreted to refer to either the setting of Protection Systems *or* to communications between entities.

To add clarity to PRC-027-1, ReliabilityFirst recommends replacing the term "coordination" with the term "Protection System Coordination." Listed below is ReliabilityFirst's proposed NERC Glossary definition of "Protection System Coordination" for the Standard Drafting Team's consideration:

***Protection System Coordination* - The setting of Protection Systems installed for the purpose of detecting and isolating Faults on BES Elements, such that the Protection Systems operate in a defined sequence in an effort to remove such Faults from the BES.**

1. **ReliabilityFirst recommends the following changes to Requirement 1, Parts 1.3.2 and 1.3.3 to incorporate this new definition of "Protection System Coordination" (highlighted in red below):**

1.3.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any Protection System Coordination Issue(s) or affirming that no Protection System Coordination issue(s) were identified.

1.3.3. Verify that identified Protection System Coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Response: Thank you for your comments.

The definition of the term Protection System Coordination Study in PRC-027-1 and its use throughout the standard is sufficient to eliminate any misunderstanding of the term coordination in Requirement R1, Parts 1.3.2 and 1.3.3. The Supplemental Material section also contains the description of the "coordination of protection" from the pending revision of IEEE Standard C37.113-1999 (Reaffirmed: 2004), Guide for Protective Relay Applications to Transmission Lines which provides further guidance regarding the term "coordination". The drafting team contends a new term "Protection System Coordination" is not warranted.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Answer Comment: Regarding R2: NIPSCO believes that measurement criteria M2 for Protection System Coordination Studies (PSCS) is not very clear. Standard needs to provide a clear direction as to what is considered an acceptable form of evidence for PSCS.

Response: Thank you for your comment.

The drafting team developed the definition of Protection System Coordination Study with a focus on producing results that achieve the purpose of PRC-027-1 (ensuring Protection Systems operate in the [entity's] intended sequence during Faults) without prescribing how the studies be performed, or how the results must be presented. Measure M2 states that documentation of the Protection System Coordination Study is acceptable evidence.

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6

Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Answer Comment: • Comments: Section R1.1: Consider adding additional clarity to the sub-requirement to limit the review to the modified BES Elements or BES Elements in the zone of protection. For example, the statement could be modified as follows: "A review and update of short circuit models for the modified BES Elements under study or BES Elements in the zone of protection." This limits the scope of the short circuit model review to just the elements being studied.

Response: Thank you for your comment. Requirement R1 mandates that an entity establish a process for developing new and revised Protection System settings for BES Elements. This process shall be used each time new or revised Protection System settings are developed. Requirement R1, Part 1.1 ensures that the model data is accurate for the System protected by the new or revised Protection Systems.

Kayleigh Wilkerson - Lincoln Electric System - 5 -

Answer Comment: LES suggests that the evidence required to meet R3 be limited and clearly defined. As currently drafted, the scope of potential evidence to demonstrate compliance with R3 would be difficult to anticipate and therefore unmanageable. Recommend the evidence be limited to entities providing short-circuit model updates (R1.1), Protection System setting reviews (R1.2), and Protection System setting coordination between owners for electrically-joined Facilities (R1.3).

LES recommends Option 2 of R2 be further clarified. It is not clear if a Protection System Coordination Study is required even if a fault current baseline hasn't deviated by 15% in 6 years. Additionally, it is also not clear what the scope of the Protection System Coordination Study is. To provide further clarity to R2 Option 2, LES suggests modifications similar to the following:

Compare present Fault current values to an established Fault current baseline in a time interval not to exceed six calendar years. A Protection System Coordination Study must be performed on the Elements connected to the bus where the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground). This Protection System Coordination Study must be completed within one calendar year of the Fault current comparison. The Fault current baseline will be updated to the present Fault current values only on the Elements for which the Protection System Coordination Study was performed.

Additionally, LES recommends protection system functions that are only enabled when other relays or associated systems fail be excluded from the R2 (e.g., overcurrent elements that are only enabled during loss of potential conditions). We feel that these protection system functions are used only as a contingency and should not fall within scope of the standard.

Response: Thank you for your comment.

Measures provide examples of evidence that may be used by entities to demonstrate compliance with the applicable requirements. The only time the "scope" of evidence could be limited is when there is only one type of evidence that will suffice.

The drafting team contends that Requirement R2 is clear that a Protection System Coordination Study is only required *"…**when the comparison identifies a 15 percent or greater deviation in Fault current values**…"*, and that it is not necessary to state the opposite – that a PSCS is not required when a 15% deviation is not identified. Further, the draft Reliability Standard Audit Worksheet (RSAW) for PRC-027-1 explains what evidence is required to demonstrate compliance with this requirement.

The drafting team developed the definition of Protection System Coordination Study with a focus on producing results that achieve the purpose of PRC-027-1 (ensuring Protection Systems operate in the [entity's] intended sequence during Faults) without prescribing how the studies be performed, or how the results must be presented. The drafting team also recognizes that Protection System designs and philosophies vary amongst entities, and performing a coordination study is more of an art than an exact science.

The drafting team reviewed PRC-023-3, Attachment A, and sees no reliability benefit in making your suggested change. Depending upon an entity's protection philosophy, the relay elements excluded by Requirement R2, Part 2.1 of PRC-023-3 Attachment A may or may not meet the criteria for inclusion in Attachment A of PRC-027-1. The protective functions listed in Attachment A of PRC-027-1 are included based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. The drafting team contends that the functions listed in Attachment A and only those functions require review when available Fault current levels increase or decrease.

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Answer Comment: The BEPC believes that the same applicability exclusion used for PRC-001-1.1 (ii) or PRC-005 should be applied to PRC-027. The key is coordination at the overall wind farm interface after the power has been aggregated. Without this exclusion, the burden of the standard outweighs any reliability benefits provided.

Response: Thank you for your comments.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

For Requirement R2, the drafting team added language to the footnote to explain that Fault current baselines for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), the common point of connection at 100 kV or above, and the BES aggregation point (total capacity greater than 75 MVA) for dispersed power producing resources.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	**Entity**	**Region**	**Segments**
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4

Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Answer Comment:

The NSRF believes that the same applicability exclusion used for PRC-001-1.1 (ii) or PRC-005 should be applied to PRC-027. The key is coordination at the overall wind farm interface after the power has been aggregated. Without this exclusion, the burden of the standard outweighs any reliability benefits provided.

The DGR applicability exclusion from PRC-001-1.1 (ii) should be added to R2, R3 or to Attachment A. FERC would not let a current requirement go unaddressed. Similarly, the individual generator exclusion from PRC-001-1.1 (ii) cannot be ignored. As an example, the following could be added to either a requirement or Attachment A:

- Requirement R2 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

The exclusion is required to address the blanket inclusion of individual wind turbines under the new Bulk Electric System (BES) definition Inclusion 4 (I4) and wording in Requirement 2 that states “each BES Element with Protection System

	functions identified in Attachment A" are to be addressed. Another alternative is the NSRF recommends an Applicability statement such as (PRC-005-2i): • 4.1.4 Protection Systems for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition: • 4.1.4.1 Protection Systems for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or above. The NSRF would like to see the words "NERC registered" added in front of the word "owner" to ensure that entities with multiple non-NERC joint owners avoid the unnecessary administrative burden of attempting to track entities with no NERC responsibilities. With PSE and possibly LSE deregistration, entities could be connected with non-NERC entities. The NERC paper process of exchanging information could become asymmetric as only one entity has legal requirements for actions and the other doesn't. Adding "NERC registered" should reduce unnecessary administration and create a symmetric or level set of requirements between affected entities. In order to take advantage of Requirement R2-Option 2, a fault current baseline must be established prior to the effective date. This sets entities up for the potential to do a considerable amount of work based upon the expectation that nothing will change between the approval date and the effective date. Given the degree of change with PRC-005, there is certainly some amount of apprehension in this regard. A better method would be to allow the entity to establish the baseline within one year after the effective date or allow a phased-in approach.

There is no requirement ensuring the Transmission Owner will share the model database or Fault current study results to allow Generation Owners and Distribution Providers to complete R2 Option 1, 2 or 3. The applicability section recognizes that the TO's are the typical entity maintaining the system model for Fault studies. NSRF prefers previous draft versions that required the TO to conduct fault studies on all buses, make comparisons and notify other entities if the fault current changed.

The 6-year frequency requirement could be relaxed to be more consistent with other relay maintenance activities or there should be more justification provided for the additional cost of more frequent analysis.

Response: Thank you for your comments.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

For Requirement R2, the drafting team added language to the footnote to explain that Fault current baselines for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), the common point of connection at 100 kV or above, and the BES aggregation point (total capacity greater than 75 MVA) for dispersed power producing resources.

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Answer Comment:

We have separately submitted a Word redline with comments. However, PSEG's comments are summarized below. We would vote "Affirmative" if the SDT adopted the changes proposed in PSEG's redline.

• We propose that the SDT modify the definition of Protection System Coordination Study by limiting it to Protection Systems for BES Elements.

• We propose that the SDT add "Transmission Planner" to the Functional Entities in Section 4.1. This change is consistent with proposed changes to delete R1.1 and add R4 so that the Transmission Planner performs Fault current studies and makes them available to their TOs, GOs, and DPs in R4. As we note in the rationale for R4:

"Transmission Planners develop short circuit data bases per MOD-032-1 and utilize them in TPL-001-4 to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt. Since Transmission Planners develop and use short circuit databases, having other entities (TOs, GOs and DPs) use them could introduce errors. Therefore, Transmission Planners should be required to calculate all Fault current values for its busses (an initial baseline and subsequent periodic updates) and make those available to its Transmission Owners, Generator Owners, and Distribution

Providers."

• In R2, we eliminated the footnote in Option 2 because proposed R4 will result in an initial Fault current baseline established by the TP on or before the effective date of the standard. Given this, when would an entity's first PSCS need to be performed for its Attachment A devices under R2? For example, if Option 2 is selected, is the first PSCS required when the baseline fault current increases by 15 percent or greater?

• Other changes in language in R1, R2, and R3 are explained in comments in the redline.

Response: Thank you for your comments.

Thank you for your suggested revisions. The drafting team reviewed them and does not agree that they are necessary or that they provide additional clarity.

The SDT asserts that the Protection Systems referenced in the definition of a Protection System Coordination Study are those that are specified in the applicability which states: "Protection Systems installed to detect and isolate Faults on BES Elements."

The drafting team disagrees that Transmission Planners need to be added to the applicability of PRC-027-1. It is the owners' responsibility to obtain any information needed to fulfill their functional entity obligations.

That is correct. Requirement R2 states that a Protection System Coordination Study is required "…when the comparison identifies a 15 percent or greater deviation in Fault current values…"

Likes:	4	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla

Dislikes:	0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer Comment:	(1) Please address each of our following comments as many of them were not addressed in the last ballot action. If these comments are not addressed, Seminole may revise its ballot vote from affirmative to negative upon the next ballot action. (2) This Standard references the terms “BES Elements.” In reviewing the NERC Glossary, there are many references to merely “Elements” without the preceding “BES” adjective, i.e., Remedial Action Scheme definition. What is the difference between “BES Elements” and “Elements” (without the BES)? Is the term “Element” without BES reference to elements that are non-BES, and if that is the case, does subpart “e.” of the RAS definition apply to non-BES Elements as there is no preceding “BES”? “BES Elements” and “Elements” are still both utilized in the Standard. Per discussions with the drafting team, it was stated that this is accidental and that there is no difference and that the team will clean these up to merely state “Elements” in the next version. (3) In R2, if a review was performed on March 1, 2017 and an entity had 6 calendar years in which to complete the review, is that 6 full calendar years? Meaning, would an entity not have to complete another review until December 31, 2023? Could you please include the above example, or an example akin to the above in the guidelines as we want to confirm we understand that 6 full calendar years are allowed, which means that more than 72 months between tests could be taken under certain timing circumstances?

(4) In R1 Part 1.5.3, this Requirement merely states that the coordination issues need to be “addressed” prior to implementation. We have two questions on this requirement, the first being that after reviewing the supplemental guidance material, that under certain circumstances, such as where additional system modifications are needed, that such modifications do not need to take place before the settings changes if the entity didn’t originally place those modifications into the scope of the settings changes project. Because the Requirement does not require the modifications to take place in any future time, can the drafting team describe in more detail how these issues are “addressed prior to implementation”? In discussions with the drafting team regarding what “addressed” means is that any coordination issues need to be agreed upon between the entities and the entities must agree to the implementation actions and a timeframe for implementation, and depending on the circumstances, “outstanding” updates can be implemented after implementation of proposed Protection System changes. Please confirm that this is correct.

(5) In the Supplemental Material section, there are references to the terms “BES Protection System” and “Protection System.” The Standard applies to “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted elements.” For purposes of this Standard, is a BES Protection System a Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted elements? There are still references to “BES Protection System” and “Protection System.” In discussions with the drafting team it was noted that all of these references were going to be cleaned up to merely state “Protection System”. Please confirm.

(6) In Requirement R1, is the 15% value 15.% with two significant figures in that if we have a deviation of 14.6% we need to perform an evaluation as it rounds up to 15% or are there more significant figures, i.e., 15.0%? This was discussed again with the drafting team that our comment wasn’t answered in the guidance,

but per a phone conversation it was stated that anything above 15.000000000 (infinity) is a violation. We'd prefer the NERC drafting teams begin honoring significant digits as it's not a difficult clarification and it makes compliance problematic because we can't tell if it's intentional or not when the drafting teams stop at a certain point. Therefore, this request is still out there, please place as many digits the team feels is significant as we will keep making this comment on every future drafted Standard, e.g., is 15.000% enough for the drafting team?

(7) In Requirement R2, if an entity uses the time based option and uses a recent short-circuit study for its baseline study, does the 6-year option 2 time frame start from the time of enforcement of the Standard or from the date the short-circuit study was finalized? The answer to this question does not appear to be in the Requirement. For Option 2, per our discussion, if a Protection System Coordination Study is performed today, the 6 year timeframe doesn't begin until the enforcement date of the Standard, correct? We are still somewhat unclear as to when the Fault current baseline comparison needs to be performed however. For example, does a Fault current baseline need to be performed every 6 years? There is some language in the Rationale box on this issue, but that language says "may" and not "shall" so it appears this isn't a requirement but merely a suggestion

(8) "Electrically joined Facilities" is not defined. Per past discussions, the intent appears to be to describe Facilities that are electrically joined AND are physically joined. Meaning, that if one Facility is 10 miles down the transmission line from another Facility, albeit "electrically joined" by electrons moving through both Facilities, the Facilities are not physically touching, and therefore, not covered by the intent of "electrically joined Facilities" under this Standard. Is this correct?

Response: Thank you for your comment.

Thank you for noting the inconsistency. The drafting team modified all references to Elements to include BES to clarify that the standard is only applicable to BES Elements.

Your understanding of the meaning of “calendar years” is correct. The drafting team included an example in the Supplemental Material.

If additional system modifications are needed, then “addressing prior to implementation” would mean it was discussed and an acceptable solution was agreed to by all parties. As noted in the Supplemental Material “There could be instances where coordination issues are identified and the entities agree not to mitigate all of the issues based on engineering judgment.” Therefore, in some cases, there may be no implementation actions.

Thank you for noting the inconsistency. The drafting team removed the BES modifier of Protection Systems in the three locations it was referenced in the Supplemental Material.

The drafting team asserts that “15 percent or greater deviation” is clear and that it is not necessary to include significant digits.

The date of the last Protection System review prior to the effective date of the standard is not relevant in considering the initial performance of Requirement R2. The six-year interval begins on the effective date of the standard. The drafting team added the following to the Implementation Plan.

1) **Initial Performance of Requirement R2**
For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

If an entity initially intends to use Option 2 as a review method for those BES Elements with Protection System functions identified in Attachment A, Fault current baselines for those BES Elements must be established prior to the effective date of the standard. Once the baseline is established, an entity must compare the Fault current baseline to the present Fault current value at the bus under study at least once every six-calendar years. The Fault current baseline is only updated each time a Protection System

Coordination Study is performed. Please see the Supplemental Material section of the standard for further discussion and examples.

Requirement R1, Parts 1.3.1 and 1.3.4 use the term “electrically joined Facilities” and are referring to Requirement R1, Part 1.3 which uses the phrase: “For Protection System settings applied on BES Elements that electrically join Facilities...” The drafting team asserts that no definition is necessary. The Facilities do not have to be physically touching to be electrically joined by a BES Element.

Mike Smith - Manitoba Hydro - 1 -

Answer Comment:

1) Manitoba Hydro suggests that the title of this standard is changed from “Coordination of Protection Systems for Performance During Faults” to: “Protection System Coordination Performance During Faults”

2) For section 1.3.4.2, “Misoperation investigation” may be better replaced by “Protection System operation investigation”

3) For R2, there seems to be no incentive (nor requirement) for entities to go with option 2 since they still have to do this study within 6 years regardless the level of fault current changes anyway.

Response: Thank you for your comments.

The drafting team declines to make the two suggested changes.

For existing Protection Systems, Requirement R2, Option 2 provides the entity the option to perform a Fault current comparison once every six-calendar-years as a trigger to determine the need for a Protection System Coordination Study (PSCS). Until a 15 percent or greater deviation in Fault current is identified through the Fault current comparisons, no PSCS is required.

Jay Barnett - Exxon Mobil - 7 -

Answer Comment:

The Supplemental Material states, "The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current availability upon request by the Distribution Provider or Generator Owner," however, there is nothing in the draft of PRC-027-1 that requires this and that would ensure this is done in a timely manner. This draft might introduce the circumstance where the GO has the responsibility to periodically compare data that the TO has and maintains. The Standard should require TOs to respond to GO requests for Fault current data in a timely manner so that the GO can perform coordination studies if necessary. Another approach would be to transfer the responsibility of performing the periodic comparisons to the TOs. If the fault current changed by 15%, then the TO would notify the affected GO so that a coordination study would be performed. The same issue would exist for small TOs that do not maintain wide-area system models.

Proposed Revision:

R2.1. Upon discovery of a change in Fault current of a BES Element owned by another GO, TO, or DP, each TO shall provide the updated Fault current values to the affected owners within 90 calendar days of discovery.

OR

R2.1. Each TO that maintains Fault current values for BES Elements owned by other GOs, TOs, or DPs, shall respond to requests for such information from the GO, TO, or DP within 90 calendar days.

Also, Requirement 3 should be limited to the attributes listed in Requirement 1 in order to have a clear and consistent measure for compliance. As written, auditors would have to become familiar with each entity's entire coordination process in order to determine compliance. Instead each entity should only have to demonstrate compliance with those attributes which the Standard Drafting Team has determined are "must have" to ensure proper coordination, as described in Requirement R1.

Proposed Revision:

R3. Each TO, GO, and DP shall utilize a process that contains the minimum attributes established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

Response: Thank you for your comments.

The drafting team disagrees that it is necessary to have a requirement that mandates the Transmission Owner share the model database or Fault current studies and declines to make the suggested change.

The drafting team contends that Requirement R3 is clear and declines to make the suggested change.

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Answer Comment:

Salt River Project (SRP) has concern over R1 part 1.1 and 1.2. As written, R1 calls for a "process for developing new and revised Protection System settings". Parts 1.1 and 1.2 requires a "review and update of short-circuit models" and a "review of the developed Protection System settings", respectively. The process defined in R1 should not have to include either review. SRP recommends changing part 1.1 and 1.2 to reflect "A methodology to evaluate ...". In previous conversations with the SDT NERC staffer, it was communicated that the intent of this requirement was to include a methodology, however the previous draft removed the language that would have signified a methodology was required. If the intent is that a process rather than the actual review is included, it should read as such.

Response: Thank you for your comment. The drafting team intends that the established process include provisions for the reviews described in Requirement R1, Parts 1.1 and 1.2. The provisions for the reviews can certainly describe an entity's methodology for achieving the reviews.

Likes: 1 Tarantino Joe On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1,
Ke

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Answer Comment: The applicability of the standard needs to be clarified so that dispersed resources at the individual resource prior to the point of aggregation are not subject to the standards requirements. In the transition from PRC-001.1ii., the exclusion for dispersed resources appears to have been improperly dropped from PRC-027-1. The PRC-027-1 mapping document lists PRC-001.1ii R3.1 and the dispersed resources sub-bullet exclusion but we cannot find a record indicating that there was discussion resulting in a deliberate intent to remove the exclusion in the transition from PRC-001.1ii to PRC-027-1. While a change to applicability prior to a final ballot is considered a substantive change in Section 4.14 of Standards Process Manual, we note that per the same section, "Where there is a question as to whether a proposed modification is "substantive," the Standards Committee shall make the final determination". We therefore request that the SDT bring this issue to the Standards Committee for consideration and include the dispersed generation exclusion in PRC-001.1ii in PRC-027-1 prior to final ballot.

Other options to address this concern could include, clarification in the Supplementary Material section, notes to auditors in the RSAW or the submission by the SDT of a SAR to change the applicability consistent with the dispersed generator exclusion as currently included in PRC-001-1ii .

Response: Thank you for your comments.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

For Requirement R2, the drafting team added language to the footnote to explain that Fault current baselines for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), the common point of connection at 100 kV or above, and the BES aggregation point (total capacity greater than 75 MVA) for dispersed power producing resources.

The drafting team provided this same information in the Rationale box, the Supplemental Material, and the RSAW.

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Answer Comment: We would like to see an exception for distributed resources similar to what project 2014-01 is working on for other standards. Typically distributed resources do not look out to the transmission system, but unless they are excluded this will need to be examined and documented.

Response: Thank you for your comments.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

For Requirement R2, the drafting team added language to the footnote to explain that Fault current baselines for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), the common point of connection at 100 kV or above, and the BES aggregation point (total capacity greater than 75 MVA) for dispersed power producing resources.

Spencer Tacke - Modesto Irrigation District - 4 -

Answer Comment: Hi,

I really believe the time period options for doing a Protection Coordination Study specified in R2 (Option 1 or Option 2) are much too large. When I used to attend the WECC Meetings on a regular basis, I remember how a high percentage of the major system outages were tied to mis-coordination or mis-operation of the protective relay systems of the various neighboring utilities. As the member's protection systems are critical to the reasonable reliability of the interconnected system, waiting six years to do another fault current check for the 15% threshold is unreasonable, or allowing no threshold current check but with a fixed 6 year time period between coordination studies, is asking for trouble. I would strongly support a one year period as the required time to do a new Protection System Coordination Study for each member's BES. Remember, NERC requires annual Transmission Planning Assessments (TPL Standards), so we should not accept any lower of a standard for a Protection System Coordination Study. Thank you.

Sincerely,

Spencer Tacke
Senior Electrical Engineer
Modesto Irrigation District
209-526-7414
spencert@mid.org.

Response: Thank you for your comment. Six-calendar years is the maximum period allowed by the standard. The standard does not preclude an entity from performing Protection System Coordination Studies more frequently, if desired.

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5 -

Answer Comment: It appears that if Option 1 is selected for R2, an entity has six years from the effective date to complete the study and also evidence for R3 would not be required until this same date. Please confirm.

Functional Entities, under Applicability and each requirement, should include Transmission Planners.

Response: Thank you for your comments.

Your understanding of Requirement R2, Option 1 is correct; however, evidence for Requirement R3 would be required if any new or revised Protection System settings were developed any time after the effective date of the standard.

The drafting team disagrees that Transmission Planners need to be added to the applicability of PRC-027-1. It is the owners' responsibility to obtain any information needed to fulfill their functional entity obligations.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Answer Comment:

Option 2 of R2 is meant to allow an entity to periodically check for a 15 percent of greater deviation in fault current. This option allows the entity to choose an interval of up to six calendar years to perform the fault current comparisons (this is derived from the PRC-027-1 supplemental material). The intent of Option 2 is not immediately clear without reading supplemental material. Given that compliance is measured only by the text of the requirement, R2 Option 2 should be clarified to indicate that if the 15 percent fault current baseline hasn't been exceeded, a protection coordination study isn't required even it if has been more than six calendar years. Or is the intent of the drafting team to state that if the 15 percent baseline threshold hasn't been exceeded a coordination study isn't required?

Additionally, the evidence retention section would benefit from clarification. There could be possible confusion with the 6 year interval of the standard versus a possible audit interval of 3 years.

Another opportunity for improvement would be to align the intervals with the intervals identified in PRC-019, which would be beneficial to GOs.

Response: Thank you for your comment.

The drafting team notes that the purpose of the Rationale boxes and Supplemental Material section is to provide additional guidance and rationale regarding the tenets of the basic requirements of the standard. Though the Rationale boxes move to the Supplemental Material section of the standard when it becomes effective, both of these informational pieces remain a permanent part of the standard for entities and auditors to reference. Further, the draft Reliability Standard Audit Worksheet (RSAW) for PRC-027-1 makes clear what evidence is required to demonstrate compliance with this requirement.

The drafting team contends that Requirement R2 is clear that a Protection System Coordination Study (PSCS) is only required *"…**when the comparison identifies a 15 percent or greater deviation in Fault current values**…"*, and that it is not necessary to state the opposite – that a PSCS is not required when a 15% deviation is not identified.

The drafting team asserts that the evidence retention section is clear and no clarification is needed.

The drafting team does not see any benefit in aligning the intervals of the two standards. PRC-027-1 does not preclude an entity from using a shorter time period than the six-calendar-years specified in Requirement R2.

William Hutchison - Southern Illinois Power Cooperative - 1 -

Answer Comment: See Comments from ACES

Response: Please see the drafting team's responses to the referenced comments.

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Answer Comment: SMUD supports Salt River Project comments.

Response: Please see the drafting team's responses to the referenced comments.

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Answer Comment: In the Supplemental Material section, there are concerns about the following paragraph: "A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider." If the generator is not a BES generator, or the generation plant is not a BES plant, the associated Protection Systems should not be under the purview of this standard unless, perhaps, they serve to provide a blocking signal to other Protection Systems associated with the BES Element or their clearing is necessary for the other Protection Systems associated with the BES Element to operate properly. For small non-BES generation, the Transmission Owner may configure its Protection Systems to properly respond with or without the small generator(s) connected. In these cases, clearing the generator(s) is arguably more about safety (isolating sources of energization) and not coordination.

	It sounds like the only triggers for conducting a Protection System Coordination Study (PSCS) are the following: (1) triggered by Requirement R2, (2) triggered by the need to establish a baseline for Requirement R2 for new BES Elements or new BES Facilities, or (3) triggered by the need to establish a baseline for Requirement R2 when transitioning between Options 1 and 2. Otherwise, if there are Protection System changes, or if there are changes to existing BES Elements, it sounds like a PSCS is not (necessarily) required, provided that the other elements identified in Requirement R1 are addressed. Is this the drafting team's intention? If a PSCS will be required for other cases, this should be more clearly identified. The verbiage in Requirement R2, Option 2, is a little unclear. For example, if Fault current values are compared within four calendar years, and the percentage change is less than 15%, does this reset the maximum six calendar year interval under Option 2? Under Requirement R1, Part 1.3.4, Tacoma Power suggests appending "...scenarios such as the following:" The Rationale for Requirement R1 includes a note about internal documentation. Tacoma Power had hoped that documentation would not explicitly be required in a scenario in which one engineering workgroup is responsible for Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, especially when those functional entities are part of the same company/organization. There is concern about the amount of extra documentation that may be involved. Furthermore, when different functional entities are part of the same company/organization, it may not be 100% clear where the DP vs. TO or TO vs. GO line should be drawn; by contrast, the same internal documentation would

not be required for internal TO-TO interaction.

The emphasis of this standard should only be to show that there is not miscoordination. It is a little awkward, but Tacoma Power suggests that the Purpose statement could be reworded to the following (CAPS added to identify suggested rewording): "To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems DO NOT operate in the UNintended sequence during Faults." Similarly, the definition of a PSCS could be reworded to the following: "An analysis to determine whether Protection Systems DO NOT operate in the UNintended sequence during Faults." Requirement R1 could be reworded to the following: "...such that the Protection Systems DO NOT operate in the UNintended sequence during Faults..."

Compared to Requirement R1, Tacoma Power is not convinced that the justification has been made for a High VRF for Requirement R3. Failing to implement one piece of the process established under Requirement R1, even for one BES Element, coupled with no graduated VSLs (see subsequent comment), would result in the maximum potential penalty.

Tacoma Power believes that the drafting team should leverage the Lower, Moderate, and High VSLs for Requriement R3. FERC's VSL G1 only states that the VSL assignment should not have the UNINTENDED consequence of lowering the current level of compliance. Furthermore, the scope of applicability of PRC-027-1 is much greater than PRC-001-1, so it is reasonable for PRC-027-1 to leverage the Lower, Moderate, and High VSLs, even though PRC-001-1 did not.

An example of a Protection System Coordination Study in the Supplemental Material section might be helpful.

Response: Thank you for your comments.

If the Distribution Provider that provides the path to the BES of a non-BES generator installs Protection Systems to detect and isolate Faults on BES Elements, then those Protection Systems would be applicable to PRC-027-1.
A Protection System Coordination Study is only required to be performed in Requirement R2.

Performance of the Fault current comparison, as provided in your example, would reset the clock for the six-calendar-year, maximum interval. Please see the example provided in the Supplemental Material section of the standard.

The drafting team declines to make the suggested change.

The note "In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation." is intended to minimize the documentation requirements for the subject functional entities. A single document that provides the required evidence would be sufficient for use by both functional entities. If an entity has a single group performing its coordination work for separate functional entities within an organization, it should make that declaration in its process.

The drafting team contends that maintaining the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults, as stated in the Purpose of PRC-027-1, achieves the same objective as ensuring the negative does not occur (that they do not operate in an unintended sequence). It is the drafting team's position that ensuring coordination is maintained requires less effort than proving that miscoordination does not exist.

Regarding Requirement R3, the drafting team disagrees and asserts that an entity is either utilizing its process or not.
The drafting team contends that failure to implement Requirement R1 could have an adverse effect on the reliability of the Bulk Electric System and, therefore, the High VRF for Requirement R3 is justified.

The drafting team did not provide an example of a Protection System Coordination Study because there are many different forms entities could use to develop their settings and verify coordination.

Glenn Pressler - CPS Energy - 1 -

Answer Comment:	R1 – Generally think there should be a bit more detail or definiation provided to "Protection System settings" that require reviewing. Does this just include element set values? Or does it also include logic settings? Drawings versus output contact programming? What about communications equipment? Keeping this wide open and letting entities define goes back down the PRC-005-1 road where some entities had much higher testing and maintenance standards, but were also held to that higher standard and punished harshly when even falling just short. R2 – Generally believe that giving the option of using fault studies or a time interval is for determining when to review coordination in R2. However, believe that if using the baseline fault studies, then the entity should have a shorter period between performing such studies. One issues with the baseline fault studies is that coordination studies may go for an additional 6 years, even if the 6 year study shows the fault current at just below the 15% threshold. I believe a 3 year or 4 year interval would be more reasonable. Otherwise, why not just use the baseline method since it too is on a 6 year interval.

Response: Thank you for your comment.

The drafting team disagrees that more detail is necessary. The Protection System settings that require reviewing are those that ensure the Protection Systems operate in the intended sequence during Faults.

Six-calendar-years is the maximum period allowed by the standard. The standard does not preclude an entity from performing Protection System Coordination Studies more frequently, if desired.

Erika Doot - U.S. Bureau of Reclamation - 5 -

Answer Comment:

Reclamation suggests that the drafting team reorder R2 and R3 for clarity. This would allow the standard to follow a logical order requiring an entity to have a system protection coordination process (R1), follow it (R2), and periodically update system protection coordination studies for functions in Attachment A (R3).

Reclamation also suggests that the drafting team update R1.3.4 to clarify that communications resulting from unforeseen circumstances may be "after-the-fact notifications" rather than requiring advance communication. This would clarify that Protection System owners do not need to wait for confirmation from owners of electrically-joined Facilities before revising Protection System settings due to unforeseen circumstances. Reclamation believes that waiting for coordination with owners of electrically joined facilities in these situations could increase risks to BES reliability from faulty Protection System settings that are discovered during commissioning, misoperation investigations, and maintenance or component failures which should be addressed immediately. Reclamation suggests that this should be clear in the requirement itself, not merely mentioned in the supplemental material.

Finally, Reclamation suggests that the drafting team update M3 to provide examples of how an entity would demonstrate that it is following the process required by R1 to include more detail regarding example evidence to show compliance with each subrequirement.

Response: Thank you for your comments.

The drafting team declines to make the suggested change. If a Protection System Coordination Study performed in accordance with Requirement R2 identifies revised settings are necessary, an entity will use its process (Requirement R3) to develop those settings.

The drafting team disagrees that further clarification is necessary regarding Part 1.3.4. As written, the drafting team contends the intent is clear that an entity may notify the other entities after any Protection System settings are revised resulting from the unforeseen circumstances.

The drafting team asserts that the evidence an entity will need to demonstrate compliance with its process will be dependent upon its process, and because every entity's process for developing settings could be different, the drafting team declines to make the suggested changes to Measure M3.

David Greene - SERC - 10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Paul Nauert	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
David Greene	SERC staff	SERC	10

Answer Comment:

1) page 4, Please revise the Purpose and Facilities to clarify the scope.
a) Purpose: "To maintain the coordination of Protection Systems installed to protect Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults."
b) Facilities: "Protection Systems installed to protect BES Elements."

Also see comment #3 below. There are a large number of DP-TO interfaces and clarity on this interface is needed.

2) page 6 Rationale Option 2: augment 'Planners and Planning Coordinators' with

'Transmission Owner' so it reads "The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Owners, Transmission Planners, or Planning Coordinators." This makes it consistent with R1 1.1 itself, page 14 explanation.

3) page 13 DP Applicability is explained by 'A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.' A) In the vast majority of cases fault current contributions from DP networks are quite weak, usually the last to trip, and insignificant to BES coordination. B) BES Phase 2 Definition excluded networks below 50kV and at the least this should be acknowledged here. C) PRC-027-1 Draft 6 Applicability language is consistent with the PRC-005-2 language, for which PRC-005-2 Supplement states: "'…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).' The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard." D) Add language similar to B and C in the PRC-027-1 Supplemental Material.

4) page 17 second option: Please clarify the Fault current location for the 15% deviation trigger is the BES bus. This will help the GO and DP understand their responsibility. Please insert BES before Element in this sentence "The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which a BES Element is connected. The drafting team intends for the 100kV or above BES

bus
to be the Fault current location."

Response: Thank you for your comments.

The drafting team contends that the acts described in the Purpose statement "…detect and isolate Faults on Bulk Electric System (BES) Elements…" are the same as providing protection for those Elements. The drafting team declines to make the suggested change. (a) The drafting team contends that the phrase provided in section 4.2. Facilities, "…detect and isolate Faults on Bulk Electric System (BES) Elements…" is the same as providing protection for those Elements. The drafting team declines to make the suggested change.

The drafting team contends that the phrase provided in section 4.2. Facilities, "…detect and isolate Faults on Bulk Electric System (BES) Elements…" is the same as providing protection for those Elements. The drafting team declines to make the suggested change.

The drafting team modified the Rationale box for Requirement R2 to include the Transmission Owner as you suggest.

Thank you for your comment. PRC-027-1 is consistent in its applicability to Protection Systems designed to detect (and isolate) Faults on BES Elements, and will, therefore follow with any definition of the Bulk Electric System as you suggest. Protection System Coordination is about isolating Faults in an intended sequence, not just about protecting Elements from Faults. PRC-027-1 will also follow with any definition of the Bulk Electric System.

The drafting team made the suggested change.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments

Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Answer Comment: **Upon our review of the most recent draft of the proposed PRC-027-1 standard, we have significant concerns regarding the expectations outlined in R1, subpart 1.2. In part 1.2, the applicable Functional Entity is required to conduct or ensure some type of review is done on its Protection System settings. While the latitude that is given to the industry on how and what type of review they are to implement is recognized, we feel that specifically mandating a quality review is unnecessary. The requirement of ensuring that quality reviews are executed is not currently included in other Protection and Control standards, and is not mandated in other standard families (with the exception of CIP-014). We do not disagree with the practice of quality assurance, however, we do not support the practice of requiring an entity to do so in a Reliability Standard. Duke Energy recommends the removal of subpart 1.2 from R1.**

Response: Thank you for your comment. The drafting team asserts that Requirement R1, Part 1.2 is an essential part of the settings development process and declines to make the suggested change.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2

Jason Smith	Southwest Power Pool Inc	SPP	2
Jonathan Hayes	Southwest Power Pool Inc	SPP	2
Robert Gray	Board of Public Utilities of Kansas City, Kansas	SPP	3
Michael Jacobs	Camstex	NA - Not Applicable	NA - Not Applicable
stephanie Johnson	Westar Energy, Inc	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Answer Comment: We have a concern about the mentioning of the Transmission Planner and Planning Coordinator in the Requirement R2 Rationale Box and those entities performing the calculations for the Fault current through short circuit analysis. The Rationale Box for Requirement R2 states "The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators". We would suggest the removal of those entities from the Rationale Box because they aren't include in the applicability section of the standard. Additionally, we feel that the fault current calculation has been addressed in the scope of the TPL Documentation. In that documentation, it is understood that the Transmission Planner or Planning Coordinator will conduct the fault current analysis on the BES facilities however, the Transmission Planner would have to coordinate with the owners and determine which protection systems would be impacted.

Response: Thank you for your comment. The drafting team notes that the purpose of the Rationale boxes and Supplemental Material section is to provide additional guidance and rationale regarding the tenets of the basic requirements of the standard. Though the Rationale boxes move to the Supplemental Material section of the standard when it becomes effective, both of these informational pieces remain a permanent part of the standard for entities and auditors to reference. Further, the draft Reliability Standard Audit Worksheet (RSAW) for PRC-027-1 explains what evidence is required to demonstrate compliance with this requirement. The drafting team declines to make the suggested change but did add the Transmission Owner as another source for Fault current values.

Gerry Adamski - Essential Power, LLC - 5 -

Answer Comment:

I believe it would be appropriate to include the Transmission Planner as an applicable entity for R2 purposes as they typically maintain the fault current/short circuit values at the buses.

I had to reread R2 a couple of times to be clear that the coordination study required as part of Option 2 only applies to the buses where the deviation exceeds 15% and not required of all the buses. If an opportunity exists, a minor clarifying edit would be recommended.

in R2, the standard speaks to a deviation at a bus to which the Element is connected. Is this intended to be a bus that is part of the BES? I'm thinking of how this would be applied at a generating plant where there is the transmission voltage level bus, the generating plant bus (e.g. 18 kV), lower voltage level buses within the plant, etc. I'm wondering how this aspect would be applied in practice at a plant. Perhaps clarifying edits in the requirement language and accompanying discourse in the rationale would help clarify this…

Response: Thank you for your comments.

The drafting team disagrees that Transmission Planners need to be added to the applicability of PRC-027-1. It is the owners' responsibility to obtain any information needed to fulfill their functional entity obligations.

As written, Option 2 specifies the performance of a Protection System Coordination Study is only required *"…when the comparison identifies a 15 percent or greater deviation in Fault current values…**at a bus to which the Element is connected**…"* Please reference the Rationale box and Supplemental Material sections of the standard for further discussion and examples associated with Requirement R2.

The Applicability section, Part 4.2. Facilities of PRC-027-1 limits the requirements of PRC-027-1 to Protection Systems installed to detect and isolate Faults on BES Elements. To address your concern, the drafting team clarified the language of Option 2 by adding the BES descriptor to modify Element. The Rationale and Supplemental Material sections also reflect this revision.

Louis Guidry - Louis Guidry On Behalf of: John Lindsey, Cleco Corporation, 6, 5, 3, 1
Michelle Corley, Cleco Corporation, 6, 5, 3, 1
Robert Hirchak, Cleco Corporation, 6, 5, 3, 1
Stephanie Huffman, Cleco Corporation, 6, 5, 3, 1

Answer Comment:

The definition of Power System Coordination Study is defined as an analysis of the operating sequence. Our interpretation of the definition is that we have to model the relay action and demonstrate that it operates in the intended sequence. Cleco uses fault simulations to develop the settings. We do not model the relays in our short-circuit program to demonstrate the relay action.

2. The standard requires an internal review of the developed settings. Who is going to review the settings currently develop? Relay settings are an art due to the compromised required because of so many unique problems. No two people are going to solve the problem exactly the same. Should two people develop the settings and compare results?

3. The standard requires a review of the short-circuit model prior to developing settings. What constitutes a valid review?

4. Requirement 1.3 says we get a response from other owners prior to implementing settings on associated BES elements. How much time before Cleco responds is required? How much time do we have to wait for a response? What if neighboring entity request a response for many of our associated systems at once?

Response: Thank you for your comments.

The drafting team chose not to be prescriptive in defining a Protection System Coordination Study. The method to perform the analysis to determine whether the Protection Systems operate in the intended sequence during Faults is left to the individual entity's discretion.

A review of the developed Protection System settings reduces the likelihood of introducing human error and verifies that the settings produced meet the technical criteria of the entity. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of reviews.

A valid review would be one that ensures that the information in the short-circuit model accurately reflects the physical power system that will form the basis of the Protection System Coordination Study and development of Protection System relay settings.

The drafting team provided flexibility for entities to establish processes that best work for their protection philosophies and business practices. Communication with neighboring entities is required for certain provisions within the process; the drafting team asserts that entities will collaborate on schedules to ensure both parties' needs are met.

Jamison Cawley - Nebraska Public Power District - 1 -

Answer Comment:

Please state that when a fault current baseline is first established we are not required to show a coordination study for every protection scheme on our system. Please state that utilities are not required to show a coordination study if the baseline continues to show a fault current change less than 15%?

Requirement R2 option 2 states “Fault current values (either three phase or phase to ground) at a bus to which the Element is connected” where the RSAW states “Fault current comparison and results for each BES Element”. The RSAW and Standard should match language as closely as possible. In this case the standard states bus faults and the RSAW evidence specifies each element which is more than just a bus. It may be wise to delay industry RSAW reviews until the standard language is in a more finalized state.

Consider adding a modification to R2. There should be an allowed time line for a coordination study to take place after the 15% fault current threshold has been identified as being exceeded. This presents a risk many could step into unwittingly when the identification is close to the 6 year interval. There are circumstances where fault currents may not change until close to this 6 year interval due to system changes that may not be foreseen. We suggest the requirement include a two year window after a 15% change is identified.

Please provide a definition or examples to clarify what is considered “electrically-joined Facilities”. For example, if a line and both terminals and protection is owned by entity A at sub 1 and sub 2. All other equipment at sub 1 is owned by entity B. All equipment at Sub 2 is owned by entity A. Is sub 2 “electrically-joined”?

The RSAW in the sections for R1 and R3 states: “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation”. We request a provision in the Standard allowing if all separate functional entities within an organization have access to the same internal documentation, then the communication aspects are not required.

In a situation where utility A does work for another utility B on their transmission system protection equipment and utility A owns all the other surrounding protection systems, please clarify how the communication evidence would change with coordination work since utility A is making all the coordination decisions. Is it acceptable to show utility A has all utility B protection system settings internally stored? Does this make utility A responsible for utility B compliance?

For a facility that has multiple bus voltages such as 115kV, 230kV and 345kV and if the fault current baseline exceeds 15% on just the 115kV bus does this mean just the elements connected to the 115kV bus must have a coordination study but not the 230 or 345kV buses?

Response: Thank you for your comments.

The drafting team asserts that Requirement R2 and the footnote clearly indicate when a Protection System Coordination Study is required based on the option(s) selected. For Option 2, the drafting team interprets both of your statements to be correct.

The language and intent of the requirements contained in the final standard will be reflected in the final RSAW.

An entity can judiciously select the interval that a comparison of present Fault current values to an established Fault current baseline is made; thereby allowing adequate time after the identification of the Fault current deviation to perform the Protection System Coordination Study.

Requirement R1, Parts 1.3.1 and 1.3.4 use the term “electrically joined Facilities” and are referring to Requirement R1, Part 1.3 which uses the phrase: “For Protection System settings applied on BES Elements that electrically join Facilities...” The drafting team asserts that no definition is necessary. For your example, sub 2 is electrically joined to sub 1; however, because the Protection Systems in both subs are owned by the same functional entity, Requirement R1, Part 1.3 is not applicable.

The note “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.” is intended to minimize the documentation requirements for the subject functional entities. A single document that provides the required evidence would be sufficient for use by both functional entities. If an entity has a single group performing its coordination work for separate functional entities within an organization, it should make that declaration in its process.

In the case where utility A performs the settings calculations for both parties (utility A & B), those settings and the associated documentation for those settings would need to be sent to utility B. Utility A would not be responsible for utility B compliance. Note that utility B is required to develop a process that may include the use of contractors to develop Protection System settings.

Yes. The drafting team agrees with your interpretation.

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2007-06 PRC-027-1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1

Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Answer Comment:

The parenthetical phrase in sub-Part 4.1.3 of the Applicability is not necessary and should be deleted. FPA 215 already ready limits the applicability of all reliability standards to the Bulk Power System and believe that NERC has revised the BES definition so that it should, either through application of bright line criteria or through the NERC or FERC exception process, encompass only those Elements and Facilities that are subject to FPA 215.

It should also be noted that, in this version the word “its” is deleted from Requirement 1 but that the Rationale for Requirement R1 uses the word “their” while Measure 1 uses the word “its”. We suggest changes be made so that all contain consistent verbiage. We believe that an entity can only be responsible for Protection System(s) it owns and would prefer this be explicitly indicated in the requirement(s).

As defined in the NERC Glossary, the Reliability Coordinator is the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and Real-time operations. The Reliability Coordinator has the purview above and beyond that of a Transmission Operator that is broad enough to enable the calculation of Interconnection Reliability Operating Limits. Because new relay settings or revisions to relay settings can impact IROL calculations, the Reliability Coordinator must be aware of any new relay settings or revised relay settings in advance of their implementation.

For these reasons the standard needs to require that each Transmission Owner, Generator Owner and Distribution Provider notify the Reliability Coordinator that it is developing new or revised relay settings. The revision should also allow for the Reliability Coordinator to provide comments on the new or revised relay settings. To capture this, we suggest the following revision to R1:

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A review and update of short-circuit models for the BES Elements under study.

1.2. A review of the developed Protection System settings.

1.3. Provide new or revised Protection System settings to the Reliability Coordinator.

1.3.1 Respond to the Reliability Coordinator's comments regarding the proposed new or revised Protection System settings by resolving any coordination issue(s) or affirming that no coordination issue(s) were identified.

1.4. For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.4.1. Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

Also, to clarify and reinforce the nature of the broader protection coordination concern, suggest the following modification to the Purpose:

"To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults without causing an inadvertent adverse impact anywhere on the BES."

We suggest that the drafting team review PRC-027-1 R1 Part 1.1 and MOD-032-1, R1 for a potential overlap, and if necessary provide clarification in the supplemental material.

R2, Option 2 has two actions associated with it, both of which have to be completed in one timeframe. The two actions are the Fault current comparison against the baseline and the performance of a Protection System Coordination Study if the fault current comparison exceeds 15% or greater deviation. It is recommended that under this option, if an entity identifies a 15% or greater deviation in Fault current value at a bus, the entity is given a set amount of time per element to complete a protection coordination study on all applicable elements at that bus.

In many cases, smaller entities that are interconnected to larger TOs do not develop their own Protection System settings. These settings are provided to them by the interconnecting TO and mandated to be implemented through Interconnection agreements. R1 should be revised to recognize these instances, including the Rationale for Requirement R1 words related to a "single protective relaying group performing the work for multiple functional entities," as a single group may be responsible for the process for multiple owners of BES Elements. The note should also be included in the Requirement and Measure as internal documentation will be used to determine the coordination aspects of Part 1.3.

Requirement R3 needs a “trigger” to initiate the process described therein. Suggest revising Requirement R3 to read:

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that determines a need for new or revised Protection System settings shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

To avoid confusion between modeling and protection short circuit modeling, suggest adding the word ”protection” to make the term used in the standard “protection short circuit”.

Response: Thank you for your comments.
The drafting team included the parenthetical to address comments received from Distribution Providers that wanted additional clarity during previous postings of PRC-027-1.

It is the intent of the drafting team that an entity is only responsible for its Protection Systems and the team asserts that the language in the requirement and the measure is clear. The drafting team declines to make the suggested change.

The drafting team appreciates the suggestions but contends they do not add to reliability and declines to make the suggested changes to the requirements and purpose of the draft standard.

There is no overlap or conflict between PRC-027-1 Requirement R1, Part 1.1 and MOD-032-1, Requirement R1. Requirement R1 Part 1.1 of PRC-027-1 ensures that the short-circuit model data is reviewed for accuracy before being used to develop new or revised Protection System settings.

Option 2 of Requirement R2 is a Fault current based methodology for determining when a Protection System Coordination Study (PSCS) must be performed for Protection System functions listed in Attachment A. The second action you mention (performing a PSCS) is only required when a 15% or greater deviation from the established baseline Fault current at the bus to which the Element is connected is identified. An entity can judiciously select the interval that a comparison of present Fault current values to an established Fault current baseline is made; thereby allowing adequate time after the identification of the Fault current deviation to perform the Protection System Coordination Study.

The note "In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation." is intended to minimize the documentation requirements for the subject functional entities. A single document that provides the required evidence would be sufficient for use by both functional entities. If an entity has a single group performing its coordination work for separate functional entities within an organization, it should make that declaration in its process. The note is also included in the RSAW.

The drafting team contends that Requirement R3 is clear that the trigger for utilizing your process is whenever you need to develop new or revised Protection System settings. The drafting team declines to make the suggested change.

The drafting team declines to make the suggested change.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment: N/A

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment: Texas RE recommends deleting the comment regarding ownership in the Functional Entities section since there is no need with risk-based compliance.

	In the Evidence Retention section, Texas RE recommends changing the statement “since the last audit” to “since the last audit of these requirements.”

Response: Thank you for your comments.

The drafting team included the parenthetical to address comments received during previous postings of the draft standard from Distribution Providers requesting additional clarity.
The referenced language in the Evidence Retention section is boilerplate language. The drafting team declines to make the suggested change.

Kenn Backholm - Snohomish County PUD No. 1 - 6 -

Answer Comment:	Public Utility District No. 1 of Snohomish County supports Salt River Project comments.

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Answer Comment:	1) Hydro One Networks Inc. agrees with the NPCC and recommends that the NERC SDT provides clarification on the overlap of requirements between MOD-032-1, R1 (to develop short-circuit modelling data requirements) and PRC-027-1, R1 (to establish a process which includes a review and update of short-circuit models). 2) Requirement R2, Option 2, entails two actions: 1) a fault current comparison against a previously established baseline be performed, and 2) a Protection System Coordination Study be performed if the results of the comparison study

exceed a deviation 15%. Presently, both these actions need to be performed within the same timeframe. However, Hydro One Networks Inc. agrees with the NPCC in that a separate time period should be allotted for an entity to complete a protection coordination study on all associa0ted elements on a bus, if a deviation of 15% or greater in the available fault current comparison is identified.

3) Further, Hydro One Networks Inc. also recommends that in the interest of clarity, the two actions within Option 2 of requirement R2 be separated out.

Response: Thank you for your comments.

There is no overlap or conflict between PRC-027-1 Requirement R1, Part 1.1 and MOD-032-1, Requirement R1. Requirement R1 Part 1.1 of PRC-027-1 ensures that the short-circuit model data is reviewed for accuracy before being used to develop new or revised Protection System settings.

Option 2 of Requirement R2 is a Fault current based methodology for determining when a Protection System Coordination Study (PSCS) must be performed for Protection System functions listed in Attachment A. The second action you mention (performing a PSCS) is only required when a 15% or greater deviation from the established baseline Fault current at the bus to which the Element is connected is identified. An entity can judiciously select the interval that a comparison of present Fault current values to an established Fault current baseline is made; thereby allowing adequate time after the identification of the Fault current deviation to perform the Protection System Coordination Study.

The drafting team declines to make the suggested change.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name:	FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Answer Comment:

1. From a standards development process perspective, FMPA recognizes that there was a fair amount of industry outreach recently on this Project. Yet, given the low results (<40%) in the prior balloting, a written "consideration of comments" would have been helpful. Plus, is it surprising that this round of questions only addresses the "Attachment A" and the "Implementation Plan" and not the actual standard language. These few questions will not necessarily gather the input needed by the SDT, in case additional improvements are needed.

2. Requirement 1.3.4 has 4 sub parts that can drive auditors to require registered entities to prove the negative. Would suggest that the four sub parts be not listed as such and instead just be collapsed into the sentence. That will reduce the likelihood that auditors will feel compelled to ask for "specific

supporting evidence to prove the negative" which we were told during outreach was not the intent of the SDT.

Part 1.3.4 *Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:*

1.3.4.1. *Implementation or commissioning.*

1.3.4.2. *Misoperation investigations.*

1.3.4.3. *Maintenance activities.*

1.3.4.4. *Emergency replacements required as a result of Protection System component failure.*

3. FMPA has previously commented that the speed at which faults are cleared is very important to reliability, and does not understand why sequence is call out in the standard and associated definitions as being more important. FMPA recommends the SDT consider adding language to R1 that requires review of Protection System settings with regard to critical clearing time.

Response: Thank you for your comments.

The drafting team appreciates your thoughts regarding a "consideration of comments" document from the previous posting and the concerning the questions associated with the most recent posting. The drafting team received many constructive changes during the previous comment period for draft 5 of the standard and chose to adopt many of them, incorporating them into draft 6. The team concentrated on improving the standard rather than responding to the many comments received. With this past posting, the questions reflected two primary aspects of the standard along with the general question that is designed to capture all other topics stakeholders want addressed or have questions on. Based on the comments submitted with this posting, that effort was successful.

The drafting team reformatted Requirement R1, Part 1.3.4 to address your concern. It now reads: Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure.

The drafting team asserts that critical clearing times are developed in planning studies and System performance is assessed through the TPL standards. PRC-027-1 is addressing the coordination of Protection Systems such that they operate in the intended sequence during Faults.

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment:

Texas RE recommends deleting the comment regarding ownership in the Functional Entities section since there is no need with risk-based compliance.

In the Evidence Retention section, Texas RE recommends changing the statement “since the last audit” to “since the last audit of these requirements.”

Texas RE is concerned there is no time frame for entities to provide settings or response to settings in R1.3 The implication is that setting should be provided before implementation by using the word “proposed” but R1.3.2 does not discuss any timeframe for a response. R1.3.4 does not discuss a time frame for communication of revised settings in an unforeseen circumstance.

The footnote for R2 could cause confusion. It is not clear that an Entity should not exceed six years between either performing a Study or comparing Fault current values. If an entity changes options before the six year mark, a Study should be done at that time to establish the baselines.

Texas RE recommends changing the severe VSL for R2 to "The responsible entity failed to perform Option 1, Option 2 or Option 3, in accordance with Requirement 2 for each element."

Response: Thank you for your comments.

The drafting team included the parenthetical to address comments received during previous postings of the draft standard from Distribution Providers requesting additional clarity.

The referenced language in the Evidence Retention section is boilerplate language. The drafting team declines to make the suggested change.

The drafting team provided flexibility for entities to establish processes that best work for their protection philosophies and business practices. Communication with neighboring entities is required for certain provisions within the process; the drafting team asserts that entities will collaborate on schedules to ensure both parties' needs are met.

The drafting team asserts the language of Requirement R2 and the footnote are clear.

The drafting team asserts the phrase "in accordance with Requirement R2" is sufficient, and declines to make the suggested change to the VSL.

Alex Chua - Pacific Gas and Electric Company - 5 -

Answer Comment: Abstain

Matt Culverhouse - City of Bartow, Florida - 3 -

Answer Comment:

1. From a standards development process perspective, we recognize that there was a fair amount of industry outreach recently on this Project. Yet, given the low results (<40%) in the prior balloting, a written “consideration of comments” would have been helpful. Plus, is it surprising that this round of questions only addresses the “Attachment A” and the “Implementation Plan” and not the actual standard language. These few questions will not necessarily gather the input needed by the SDT, in case additional improvements are needed.

Response: Thank you for your comment. The drafting team appreciates your thoughts regarding a “consideration of comments” document from the previous posting and the concerning the questions associated with the most recent posting. The drafting team received many constructive changes during the previous comment period for draft 5 of the standard and chose to adopt many of them, incorporating them into draft 6. The team concentrated on improving the standard rather than responding to the many comments received. With this past posting, the questions reflected two primary aspects of the standard along with the general question that is designed to capture all other topics stakeholders want addressed or have questions on. Based on the comments submitted with this posting, that effort was successful.

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Answer Comment:

The requirement to coordinate protective relay settings has existed since the first power systems were built. BC Hydro, like all utilities, has been coordinating their protection systems as part of their normal practice and has a process for setting development, review and implementation on its protection systems. While the requirements in Draft 6 of PRC-027-1 are not substantially different than standard industry practice, proving annual compliance with these requirements (to the satisfaction of lawyers) will impose a large administrative burden. The original focus of PRC-001 made sense in that there are always communications and data gathering issues that make coordinating protection systems across different utilities more challenging than coordinating within one's own system. The new draft standard focuses too much of the utility's time and effort on proving compliance on a process that typically works well, which reduces the amount of time and effort that can be spent on areas where more time and money should be spent.

Response: Thank you for your comment. The drafting team agrees that most entities have processes to develop Protection System settings that achieve proper coordination of the Bulk Electric System. Utilizing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, decreases the possibility of introducing errors, and increases the likelihood of maintaining a coordinated Protection System. The drafting team contends these requirements were crafted in a manner that provides entities the ability to continue to follow their individual protection philosophies and practices, with minimal administrative impact.

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments

Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Answer Comment:

The Planning Coordinator, Reliability Coordinator, and Balancing Authority must be notified when new or revised protection settings are developed.

As defined in the NERC Glossary, the Planning Coordinator is the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems. Because the Planning Coordinator is responsible for the coordination and integration of protection systems, it must be aware of any new relay settings or revised relay settings in advance of their implementation.

As also defined in the NERC Glossary, the Reliability Coordinator is the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision. Because new relay settings or revisions to relay settings can impact IROL calculations, the Reliability Coordinator must be aware of any new

relay settings or revised relay settings in advance of their implementation.

Finally, draft requirements in the proposed TOP-009-1 reliability standard require that the Balancing Authority ensure that "… its personnel responsible for Reliable Operation of its Balancing Authority Area have knowledge of operational functionality and effects of Composite Protection Systems and Remedial Action Schemes that are necessary to perform its Real-time monitoring in order to maintain generation-Load-Interchange balance." Accordingly, Balancing Authorities will need to be provided with new or revised Protection System settings to fulfill its obligations under TOP-009-1.

Therefore, the standard needs to require that each Transmission Owner, Generator Owner and Distribution Provider notify the Planning Coordinator, Reliability Coordinator, and Balancing Authority that it is developing new or revised relay settings. The revision should also allow for the Planning Coordinator or Reliability Coordinator to provide comments on the new or revised relay settings. To capture this, the ISO/RTO Council Standards Review Committee suggests the following revision in R1:

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1 A review and update of short-circuit models for the BES Elements under study.

1.2 A review of the developed Protection System settings.

1.3 Provide new or revised Protection System settings to the Planning Coordinator, Reliability Coordinator, and Balancing Authority.

1.3.1 Respond to the Planning Coordinator or Reliability Coordinator's comments regarding the proposed new or revised Protection System settings.

1.4 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.4.1 Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

Also, to clarify and reinforce the nature of the broader protection coordination concern, the following modification to the Purpose is proposed:

"To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults without causing an inadvertent adverse impact anywhere on the BES."

Response: Thank you for your comments.
The drafting team appreciates the suggestions but contends those changes are not necessary in PRC-027-1. Between Phase 1 and Phase 2 of System Protection Coordination, all of the planning and operational aspects of coordination are addressed. The drafting team declines to make the suggested changes.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name:	Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Answer Comment:

We request that the SDT consider the following changes/ clarifications:

Present language:

R1.1 A review and update of short-circuit models for the BES Elements under study.

Proposed:

R1.1 A review and update of short-circuit models or data for the BES Elements under study.

This change will address concerns from GOs and DPs that don't have anything to do with the short-circuit model and potentially only need the fault current data at the interconnected bus from the TO.

In the rational box for **R2:**

Present language:

The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators.

Proposed language:

The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators or Transmission Owners.

Response: Thank you for your comments. The drafting team made the suggested clarifying changes.

Tony Eddleman - Nebraska Public Power District - 3 -

Answer Comment:

Please state that when a fault current baseline is first established we are not required to show a coordination study for every protection scheme on our system. Please state that utilities are not required to show a coordination study if the baseline continues to show a fault current change less than 15%?

Requirement R2 option 2 states "Fault current values (either three phase or phase to ground) at a bus to which the Element is connected" where the RSAW states "Fault current comparison and results for each BES Element". The RSAW and Standard should match language as closely as possible. In this case the standard states bus faults and the RSAW evidence specifies each element which is more than just a bus. It may be wise to delay industry RSAW reviews until the standard language is in a more finalized state.

Consider adding a modification to R2. There should be an allowed time line for a coordination study to take place after the 15% fault current threshold has been identified as being exceeded. This presents a risk many could step into unwittingly when the identification is close to the 6 year interval. There are

	circumstances where fault currents may not change until close to this 6 year interval due to system changes that may not be foreseen. We suggest the requirement include a two year window after a 15% change is identified. Please provide a definition or examples to clarify what is considered "electrically-joined Facilities". For example, if a line and both terminals and protection is owned by entity A at sub 1 and sub 2. All other equipment at sub 1 is owned by entity B. All equipment at Sub 2 is owned by entity A. Is sub 2 "electrically-joined"? The RSAW in the sections for R1 and R3 states: "In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation". We request a provision in the Standard allowing if all separate functional entities within an organization have access to the same internal documentation, then the communication aspects are not required. In a situation where utility A does work for another utility B on their transmission system protection equipment and utility A owns all the other surrounding protection systems, please clarify how the communication evidence would change with coordination work since utility A is making all the coordination decisions. Is it acceptable to show utility A has all utility B protection system settings internally stored? Does this make utility A responsible for utility B compliance? For a facility that has multiple bus voltages such as 115kV, 230kV and 345kV and if the fault current baseline exceeds 15% on just the 115kV bus does this mean just the elements connected to the 115kV bus must have a coordination study but not the 230 or 345kV buses?

Response: Thank you for your comments.

The drafting team asserts that Requirement R2 and the footnote clearly indicate when a Protection System Coordination Study is required based on the option(s) selected. For Option 2, the drafting team interprets both of your statements to be correct.

The language and intent of the requirements contained in the final standard will be reflected in the final RSAW.

An entity can judiciously select the interval that a comparison of present Fault current values to an established Fault current baseline is made; thereby allowing adequate time after the identification of the Fault current deviation to perform the Protection System Coordination Study.

Requirement R1, Parts 1.3.1 and 1.3.4 use the term “electrically joined Facilities” and are referring to Requirement R1, Part 1.3 which uses the phrase: “For Protection System settings applied on BES Elements that electrically join Facilities...” The drafting team asserts that no definition is necessary. For your example, sub 2 is electrically joined to sub 1; however, because the Protection Systems in both subs are owned by the same functional entity, Requirement R1, Part 1.3 is not applicable.

The note “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.” is intended to minimize the documentation requirements for the subject functional entities. A single document that provides the required evidence would be sufficient for use by both functional entities. If an entity has a single group performing its coordination work for separate functional entities within an organization, it should make that declaration in its process.

In the case where utility A performs the settings calculations for both parties (utility A & B), those settings and the associated documentation for those settings would need to be sent to utility B. Utility A would not be responsible for utility B compliance. Note that utility B is required to develop a process that may include the use of contractors to develop Protection System settings.

Yes. The drafting team agrees with your interpretation.

Likes: 1 Nebraska Public Power District, 1, Cawley Jamison

Nebraska Public Power District, 1, Cawley Jamiso

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Answer Comment:

SCL GENERAL COMMENTS

1) The Option 2 baseline should include a system-wide review of the entities instantaneous overcurrent elements, that are utilized on the BES, as well as the performance of the baseline fault study.

SCL experience has demonstrated that overreaching instantaneous overcurrent elements are one of the largest causes of miscoordination in a Protective Relay System.

2) The draft Standard, in its present form, is reminiscent of the early stages of the PRC-005 (Relay Maintenance) Standard, in that each utility will establish their own implementation (issue and installation of the relay settings) schedule timeline, without any constraints. This did not work well, for Standard PRC-005 as the utilities with strong maintenance plans were scrutinized, during audits, much more rigorously than those utilities with weaker maintenance plans, even though the weaker maintenance plans made the BES less reliable. It required several revisions of the PRC-005 Standard to get everyone on the same playing field. SCL believes that a similar situation will occur if a not-to-exceed schedule timeline is not established for the implementation of the revised relay settings.

R1. - Introduction

Modify text in paragraph to read: such that the Protection Systems, associated with the protective functions listed in Attachment A, operate in the intended sequence during faults.

R1. – Add Section 1.4

Inside of this section describe the timeline allowed to implement the revised relay settings.

For example, “new and revised relay settings necessary for the coordination of the Protection Systems, associated with the protective functions listed in Attachment A, shall be issued and installed within one year after the Protection Coordination Study has been performed”.

R2. – Option 2

Modify text in paragraph to include the following steps:

1) Compare the present fault current values to the previously established fault current baseline at each BES bus within the entitiy’s system, with Protection Systems, associated with the protective functions listed in Attachment A.

2) Identify the buses where the present fault current value exceeds the baseline value by an amount that is 15%, or greater, in magnitude.

3) Perform a Protection System Coordination Study on the area of the system defined by the BES elements that are connected to the buses identified in Step 2.

4) The time interval to perform steps 1-3 shall not exceed six calendar years.

ATTACHMENT A

Modify text for relay elements as follows (line number defined at beginning of sentence):

21-1 – Zone 1 distance relay if:

• Infeed is used in determining reach (phase & ground distance), or

• zero-sequence mutual coupling is used in determining reach (ground distance)

21-2 – Zone 2 distance relay if:

• Infeed is used in determining reach (phase & ground distance), or

• zero-sequence mutual coupling is used in determining reach (ground distance)

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent if used in a non-communication-assisted protection scheme.

67 I – Directional Instantaneous overcurrent

67 T – Directional inverse time overcurrent if used in a non-communication-assisted protection scheme.

SUPPLEMENTAL MATERIAL REQUIREMENT R1

Modify the text for the last paragraph of Section R1 just above Part 1.1 to read:

The coordination of some Protections Systems may seem unnecessary, such as for a line element that is protected solely by dual current differential relays with other Protection Systems of the line element such that tripping does not unnecessarily occur for faults outside of the differential zone, unless there is a Protection System failure on the adjacent line element.

Response: Thank you for your comments.

The standard does not preclude an entity from performing a system-wide review of its instantaneous overcurrent elements, if desired. The drafting team declines to make the suggested change.

The drafting team declines to make the suggested changes.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Answer Comment: ATC recommends revising PRC-027-1 to identify a clear connection between performance and the requirements of this standard. Where PRC-004 data provides a mechanism to measure performance, the better means to achieve reliability performance would allow each entity to use its company's misoperations data and the greater industry data to develop a program that addresses its greatest need.

Response: Thank you for your comment. PRC-027-1 does not preclude an entity from evaluating its System based on PRC-004 data as another tool to minimize Misoperations due to coordination issues.

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - PRC-027 Project

Group Member Name	Entity	Region	Segments
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Answer Comment:

1. For requirement R1, Part 1.1, the requirement states that the TO, GO, and DP must have a process to review and update short-circuit models for BES Elements under study. We disagree that the GO and DP must complete their own short-circuit models. Our recommendation is to allow GOs and DPs to use the TO's short circuit study for applicable GO or DP buses.
2. For requirement R1, Part 1.3, we disagree with the requirement of documenting internal coordination, especially considering that smaller entities may have a single protection engineer that is responsible for completing the study. Also, we disagree that there needs to be eight sub-parts for joint ownership coordination. This is administrative in nature and burdensome for compliance. This sub-part is overly complicated and creates opportunities for entities to fall out of compliance. There is little benefit to reliability for having this much detail required.
3. For requirement R2, option 1, performing studies for all applicable relays can be resource intensive, especially for smaller entities. We recommend that the drafting team consider the Cost Effective Analysis Process (CEAP) to determine if the reliability benefits outweigh the cost of compliance.
4. For requirement R2, option 2, the baseline process is complicated. We recommend stating in footnote one that the baseline for option 2 must be completed within 12 months after the standard goes into effect. Also, the measure should state that if there is not a fault current deviation greater than 15 percent, then an attestation is sufficient evidence for compliance.
5. For requirement R2, option 3, there should be specific guidance in the measures to demonstrate compliance for the combined approach, such as a

baseline for applicable distance or overcurrent relays to occur within 12 months of the effective date and a Protection System Coordination Study (PSCS) for the remaining applicable Protection Systems to occur every 6 years after the effective date.

6. For requirement R3, the documentation requirements for coordination activities of new/revised settings is administrative in nature. We question the need for an administrative documentation requirement that is assessed a high risk. Industry has long history of coordinating Protection Systems and there is not any evidence of a widespread lack of Protection System coordination. We do not see how requiring a documented process will reduce the risks to reliability. Thus, we do not see how it enhances reliability and believe it could actually detract by causing applicable entities to focus on paperwork.

Response: Thank you for your comments.

The drafting team made a clarifying change in the Requirement and complementary changes in the Rational Box and Supplemental Material.

The note "In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation." is intended to minimize the documentation requirements for the subject functional entities. A single document that provides the required evidence would be sufficient for use by both functional entities. The drafting team contends that Part 1.3 is not administrative. The reliability objective is to ensure that the owners of Protection Systems have communicated and addressed any identified coordination issues prior to implementing the Protection Systems.

The drafting team does not agree that the work associated with Requirement R2, Option 1 is extensive, particularly for smaller entities. Entities have the choice to utilize Option 2.

Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

The drafting team contends that utilizing the process established in Requirement R1 ensures a consistent approach to the development of accurate Protection System settings, decreases the possibility of introducing errors, and increases the likelihood of maintaining a coordinated Protection System.

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4 -

Answer Comment:

FE's primary concern relates to what is required of the GO to be able to comply with R1 which states the TO, GO and DP "… establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults." The GO, operates the units essentially as isolated BES elements. The term "sequence" infers it is referring to the BES as a whole, at least with regard to interconnected elements, which would then mean we need a joint process with the TO. The GO is not in a position to make that happen, nor should the GO have primary responsibility. This should be a TO responsibility, with GO providing settings as requested by TO, and GO changing settings as requested/instructed by the TO.

FE believes the TO should be identified as the entity to establish the system protection coordination and be responsible for PSCSs (Power System Coordination Studies), Fault Studies, Short Circuit Studies, etc., to prove coordination. Communication to the GO should also be the TO's responsibility. The GO would be responsible to implement setting changes as directed by the TO, where applicable and if able. The GO's connection to the BES normally ends/terminates with the Generator Step Up transformer so the GO does not have the data to perform any Power System Coordination Studies, Fault Studies, or Short Circuit Studies

Response: Thank you for your comments.

The drafting team disagrees with your premise. The drafting team contends that the Generator Owner needs to have a process to develop its Protection System settings and must follow Requirement R1, Part 1.3 to ensure they coordinate with the Transmission Owner. The Generator Owner has the ultimate responsibility, not the Transmission Owner, for setting its Protection Systems such that they operate in the intended sequence during Faults.

The drafting team agrees that the Transmission Owner may provide the Generator Owner the short-circuit model data; however, the Generator Owner still needs to have a process to develop its Protection System settings and must follow Requirement R1.

End of report

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: "To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults." PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii).

Completed Actions	Date
Standard Authorization Request (SAR) posted for comment	June 11 – July 10, 2007
SAR approved	August 13, 2007
Draft 1 of PRC-001-2 posted for comment	September 11 – October 26, 2009
Draft 1 of PRC-027-1 posted for formal comment with ballot	May 21 – July 5, 2012
Draft 2 of PRC-027-1 posted for formal comment with ballot	November 16 – December 17, 2012
Draft 3 of PRC-027-1 posted for formal comment with ballot	June 4 – July 3, 2013
Draft 4 of PRC-027-1 posted for formal comment with ballot	November 4 – December 31, 2013
Draft 5 of PRC-027-1 posted for informal comment	October 1 – October 21, 2014
Draft 5 of PRC-027-1 posted for formal comment with ballot	April 1 – May 15, 2015
Draft 6 of PRC-027-1 posted for formal comment with ballot	July 29 – September 11, 2015
Draft 6 of PRC-027-1 posted for 10-day final ballot.	October 5 – 14, 2015

Anticipated Actions	Date
NERC Board of Trustees (BOT) adoption	November, 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Protection System Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Protection System Issues Addressed by Other Reliability Standards:

Fault clearing is the only aspect of protection coordination addressed by Reliability Standard PRC-027-1. Including aspects of protection coordination other than Fault coordination would cause duplication or conflict with the requirements of other Reliability Standards. Specifically, other protection issues, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following Reliability Standards:

- Underfrequency Load shedding programs are addressed in PRC-006-2.
- Undervoltage Load shedding programs are addressed in PRC-010-1.
- Generator performance during declined frequency and voltage excursions is addressed in PRC-024-1.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-1.
- Transmission relay loadability is addressed in PRC-023-3.
- Generator relay loadability is addressed in PRC-025-1.
- Protective relay response during stable power swings is addressed in PRC-026-1.
- Protection System Misoperations (including those caused by coordination issues) are addressed in PRC-004-3.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Coordination of Protection Systems for Performance During Faults**
2. **Number:** PRC-027-1
3. **Purpose:** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.
4. **Applicability:**

    4.1. Functional Entities:

    4.1.1. Transmission Owner

    4.1.2. Generator Owner

    4.1.3. Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 below)

    4.2. Facilities: Protection Systems installed to detect and isolate Faults on BES Elements.

5. **Effective Date:** See the Implementation Plan for PRC-027-1, Project 2007-06 System Protection Coordination.

B. Requirements and Measures

Rationale for Requirement R1:

Coordinated Protection Systems enhance reliability by isolating faulted equipment, thus reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. The stated purpose of this standard is: "To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults." Requirement R1 captures this intent by requiring responsible entities establish a process that, when followed, allows for their Protection Systems to operate in the intended sequence during Faults. Requirement R1, Parts 1.1 through 1.3 are key elements to the process for developing Protection System settings.

Part 1.1 Reviewing and updating the short-circuit model data used to develop new or revised Protection System settings helps to assure that settings are developed using accurate, up-to-date information. Generator Owners and Distribution Providers may not have or maintain short-circuit models; consequently, these entities would obtain the short-circuit model data from the Transmission Planners, Planning Coordinators, or Transmission Owners.

Part 1.2 A review of the developed Protection System settings reduces the likelihood of introducing human error and verifies that the settings produced meet the technical criteria of the entity. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of reviews.

Part 1.3 The coordination of Protection Systems associated with BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) is essential to the reliability of the BES. Communication and review of proposed settings among these entities are necessary to identify potential coordination issues and address the issues prior to implementation of any proposed Protection System changes.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

Unforeseen circumstances could require immediate changes to Protection System settings. Requirement R1, Part 1.3.4 requires owners to include provisions to communicate those unplanned settings changes after-the-fact to the other owner(s) of the electrically joined Facilities.

Note: In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A review and update of short-circuit model data for the BES Elements under study.

1.2. A review of the developed Protection System settings.

1.3. For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.3.1. Provide the proposed Protection System settings to the owner(s) of the electrically joined Facilities.

1.3.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

1.3.3. Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

1.3.4. Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity established a process to develop settings for its Protection Systems, in accordance with Requirement R1.

Rationale for Requirement R2:

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires Transmission Owners, Generator Owners, and Distribution Providers to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. The numerical identifiers in Attachment A represent general protective device functions per ANSI/IEEE *Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Requirement R2 provides entities with options to assess the state of their Protection System coordination.

Option 1 is a time-based methodology. The entity may choose to perform, at least once every six-calendar years, a Protection System Coordination Study for each of its Protection Systems identified in Attachment A. The six-calendar-year time interval was selected as a balance between the resources required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

Option 2 is a Fault current-based methodology. If Option 2 is initially selected, Fault current baseline(s) must be established prior to the effective date of this Reliability Standard. A baseline may be established when a new BES Element is installed or after a Protection System Coordination Study has been performed. The baseline(s) will be used as control point(s) for future Fault current comparisons. The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators, or Transmission Owners. In a time interval not to exceed six-calendar years following the effective date of this standard, an entity must perform a Fault current comparison. If the comparison identifies a deviation less than 15 percent, no further action is required for that six-year interval; however, if the comparison identifies a 15 percent or greater deviation in Fault current values (either three-phase or phase-to-ground) at each bus to which the BES Element is connected, the entity must also perform a Protection System Coordination Study during the same six-year interval. The baseline Fault current value(s) will be re-established whenever a new Protection System Coordination Study is performed. Fault current changes on the System not directly associated with BES modifications are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection System functions (identified in Attachment A of this standard) during Fault conditions. A Fault current deviation threshold of 15 percent or greater (as compared to the established baseline) and a maximum time interval of six calendar years were chosen for these evaluations. These parameters provide an entity with latitude to choose a Fault current threshold and time interval that best match its protection philosophy, Protection System maintenance schedule, or other business considerations, without creating risk to reliability (See the Supplemental Material section for more detailed discussion).

The footnote in Option 2 describes how an entity may change from a time-based option to a Fault current-based option for existing BES Elements as well as establishing baselines for new BES Elements by performing Protection System Coordination Studies. The footnote also states that Fault current baselines for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA).

Option 3 provides the entity the choice of using both the time-based and Fault current-based methodologies. For example, the entity may choose to utilize the time-based methodology for Protection Systems at more critical Facilities and use the Fault current-based methodology for Protection Systems at other Facilities.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six-calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the

comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the BES Element is connected, all in a time interval not to exceed six-calendar years;[1] or,

- Option 3: Use a combination of the above.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity performed Protection System Coordination Study(ies) and/or Fault current comparisons in accordance with Requirement R2.

Rationale for Requirement R3:

Utilizing the processes established in Requirement R1 to develop new and revised Protection System settings provides a consistent approach to the development of Protection System settings and will minimize the potential for errors.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity utilized its settings development process established in Requirement R1, as specified in Requirement R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than

[1] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. The Fault current baseline for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA). If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity may establish the baseline by performing a Protection System Coordination Study.

the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance with Requirements R1, R2, and R3, and Measures M1, M2, and M3 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 or Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.3. OR The responsible entity failed to establish any process in accordance with Requirement R1.
R2.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3 but was late by less than or equal to 30 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 90 calendar days. OR The responsible entity failed to perform Option 1, Option

				2, or Option 3, in accordance with Requirement R2.
R3.	N/A	N/A	N/A	The responsible entity failed to utilize the process established in accordance with Requirement R1.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee – "Power Plant and Transmission System Protection Coordination."

NERC System Protection and Control Task Force, December 7, 2006, "Assessment of Standard PRC-001-0 – System Protection Coordination."

NERC System Protection and Control Task Force, September 2006, "The Complexity of Protecting Three-Terminal Transmission Lines."

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	New standard developed under Project 2007-06

Attachment A

The following Protection System functions[2] are applicable to Requirement R2 if: (1) available Fault current levels are used to develop the settings for those Protection System functions; and (2) those Protection System functions require coordination with other Protection Systems.

21 – Distance if:

- infeed is used in determining reach (phase and ground distance), or
- zero-sequence mutual coupling is used in determining reach (ground distance).

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent

67 – AC directional overcurrent if used in a non-communication-aided protection scheme

Notes:

1. The above Protection System functions utilize current in their measurement to initiate tripping of circuit breakers. Changes in the magnitude of available Fault current can impact the coordination of these functions.
2. See the PRC-027-1 Supplemental Material section for additional information.

[2] ANSI/IEEE Standard C37.2 *Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Purpose

The Purpose states: To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.

Coordinated Protection Systems enhance reliability by isolating faulted equipment, reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. This standard requires that entities establish and implement a process to coordinate their Protection Systems to operate in the intended sequence during Faults.

Applicability

Transmission Owners, Generator Owners, and Distribution Providers are included in the Applicability of PRC-027-1 because they may own Protection Systems that are installed for the purpose of detecting Faults on the Bulk Electric System (BES). It is only those Protection Systems that are under the purview of this standard.

Transmission Owners are included in the Applicability of PRC-027-1 because they own the largest number of Protection Systems installed for the purpose of detecting Faults on the BES.

Generator Owners have Protection Systems installed for the purpose of detecting Faults on the BES. It is important that those Protection Systems are coordinated with Protection Systems owned by Transmission Owners to ensure that generation Facilities do not become disconnected from the BES unnecessarily. Functions such as impedance reaches, overcurrent pickups, and time delays need to be evaluated for coordination.

A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.

After the Protection Systems of Distribution Providers and Generator Owners are shown to be coordinated with other Protection Systems on the BES, there will be little future impact on the entities unless there are significant changes at or near the bus that interconnects with the Transmission Owner. The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current data upon request by the Distribution Provider or Generator Owner. The Distribution Provider and Generator Owner will determine whether a change in Fault current from the baseline has occurred such that a review of coordination is necessary.

Requirement R1

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults.

The reliability objective of this requirement is to have applicable entities establish a process to develop settings for coordinating their Protection Systems, such that they operate in the intended sequence during Faults. The parts that are included as elements of the process ensure the development of accurate settings, as well as providing internal and external checks to minimize the possibility of errors that could be introduced in the development of settings.

This standard references various publications that discuss protective relaying theory and application. The description of "coordination of protection" is from the pending revision of IEEE Standard C37.113-1999 (Reaffirmed: 2004), *Guide for Protective Relay Applications to Transmission Lines*, which reads:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Entities may have differing technical criteria for the development of Protection System settings based on their own philosophies. These philosophies can vary based on system topology, protection technology utilized, as well as historical knowledge; as such, a single definition or criterion for "Protection System coordination" is not practical.

The coordination of some Protection Systems may seem unnecessary, such as for a line that is protected solely by dual current differential relays. However, backup Protection Systems that are enabled to operate based on current or apparent impedance with some definite or inverse time delay must be coordinated with other Protection Systems of the BES Element such that tripping does not unnecessarily occur for Faults outside of the differential zone.

Part 1.1 A review and update of short-circuit model data for the BES Elements under study.

The short-circuit study provides the necessary Fault currents used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers. Generator Owners and Distribution Providers may not have or maintain short-circuit models; consequently, these entities would obtain the short-circuit model data from the Transmission Planners, Planning Coordinators, or Transmission Owners. Including a review and, if necessary, an update of short-circuit study information is necessary to ensure that information accurately reflects the physical power system that will form the basis of the Protection System Coordination Study and development of Protection System relay settings. The results of a short-circuit study are only as accurate as the information that its calculations are based on.

A short-circuit study is an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical Fault. Because the results of short-circuit studies are used as the basis for protective device coordination studies, the short-circuit model should accurately reflect the physical power system.

Reviews could include:

1. A review of applicable BES line, transformer, and generator impedances and Fault currents.
2. A review of the network model to confirm the network in the study accurately reflects the configuration of the actual System, or how the System will be configured when the proposed relay settings are installed.
3. A review, where applicable, of interconnected Transmission Owner, Generator Owner, and Distribution Provider information.

Part 1.2 A review of the developed Protection System settings.

A review of the Protection System settings prior to implementation reduces the possibility of introducing human error. A review is any systematic process of verifying the developed settings meet the technical criteria of the entity. Examples of reviews include peer reviews, automated checking programs, and entity-developed review procedures.

Part 1.3 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

Requirement R1, Part 1.3 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities. Communication among these entities is essential so potential Protection System coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

Part 1.3.1 1.3.1. Provide the proposed Protection System settings to the owners of the electrically joined Facilities.

Requirement R1, Part 1.3.1 requires the entity to include in its process a provision to provide proposed Protection System settings to other entities. This communication ensures that the other entities have the necessary information to review the settings and determine if there are any Protection System coordination issues.

Part 1.3.2 Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

Requirement R1, Part 1.3.2 requires the entity receiving proposed Protection System settings to include in its process a provision to respond to the entity that initiated the proposed changes. This ensures that the proposed settings are reviewed and that the initiating entity receives a response indicating Protection System coordination issues were identified, or affirmation that no issues were identified.

Part 1.3.3 Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Requirement R1, Part 1.3.3 requires the entity to include in their process a provision to verify that any identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation. This ensures that any potential impact to BES reliability is minimized.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

Note: There could be instances where coordination issues are identified and the entities agree not to mitigate all of the issues based on engineering judgment. It is also recognized that coordination issues identified during a project may not be immediately resolved if the resolution involves additional system modifications not identified in the initial project scope. Further, there could be situations where protection philosophies differ between entities, but the entities can agree that these differences do not create coordination issues.

Part 1.3.4 Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure.

Requirement R1, Part 1.3.4 requires the entity to communicate revisions to Protection System settings that occur due to unforeseen circumstances and differ from those developed during the planning stages of projects.

Requirement R2

This requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A:

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six-calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the BES Element is connected, all in a time interval not to exceed six-calendar years;[3] or,

[3] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. The Fault current baseline for BES

- Option 3: Use a combination of the above.

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. Two triggers were established for initiating a review of existing Protection System settings to allow for industry flexibility.

In the first option, an entity may choose a time-based methodology to review Protection System settings, thus eliminating the necessity of establishing a Fault current baseline and periodically performing Fault current comparisons. This option provides the entity the flexibility to choose an interval of up to six-calendar years for performing the Protection System Coordination Studies for those Protection System functions in Attachment A. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which a BES Element is connected. Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators, or Transmission Owners. This option allows the entity to choose an interval of up to six-calendar years to perform the Fault current comparisons and Protection System Coordination Studies. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. A maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) was established based on generally-accepted margins for setting Protection Systems in which incremental Fault current changes would not interfere with coordination. The 15 percent maximum deviation provides an entity with latitude to choose a Fault current threshold that best matches its protection philosophy, or other business considerations. The Fault current based option requires an entity to first establish a Fault current baseline to be used as a point of reference for future Fault current studies. The Fault current values used in the percent change calculation, whether three-phase or phase-to-ground Fault currents, are typically determined with all generation in service and all transmission BES Elements in their normal operating state.

As described in the footnote for Requirement R2, Option 2, an entity that elects to initially use Option 2 must establish its baseline prior to the effective date of the standard. If an initial

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generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA). If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity may establish the baseline by performing a Protection System Coordination Study.

baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity may establish the baseline upon performing a Protection System Coordination Study. The Fault current baseline values can be updated or established when a Protection System Coordination Study is performed. The baseline values at each bus to which a BES Element is connected are updated whenever a new Protection System Coordination Study is performed for the subject Protection System. The footnote also states that the Fault current baselines may be established for BES generating resources at the generator, the BES aggregation point for dispersed power producing resources, or at the common point of connection at 100 kV or above.

> **Example:** Prior to the effective date of PRC-027-1, an entity intending to use Option 2 of Requirement R2 establishes an initial baseline; e.g., 10,000 amps at the bus to which the BES Element under study is connected. A short-circuit review performed on March 1, 2024, for example, identifies that the Fault current has increased to 11,250 amps (12.5 percent deviation); consequently, no Protection System Coordination Study is required since the increase is below the maximum 15 percent deviation. The baseline value for the next comparison (to be performed no later than December 31, 2030) remains at 10,000 amps because no study was required as a result of the initial comparison. During the next six-year interval, Fault current comparison identifies that the Fault current has increased to 11,500 (15 percent deviation); therefore, a Protection System Coordination Study is required (and must also be completed no later than December 31, 2030), and a new baseline of 11,500 amps would be established.

> **Note:** In the first review described above, if the entity decides to perform a Protection System Coordination Study at the 12.5 percent deviation and the results of the study indicate that the settings still meet the setting criteria of the entity, then no settings changes are required and the baseline Fault current(s) would be updated.

As a third option, an entity has the flexibility to apply a combination of the two methodologies. For example, an entity may choose the periodic Protection System review (Option 1) and review its Facilities operated above 300 kV on a six-calendar-year interval, while choosing to use the Fault current comparison (Option 2) for its Facilities operated below 300 kV.

The Protection System functions listed in Attachment A utilize AC current in their measurement to initiate tripping of circuit breakers and the coordination of these functions is susceptible to changes in the magnitude of available short-circuit Fault current. These functions are included in Attachment A based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. Examples of functions not included in Attachment A because they do not meet both of the criteria are differential relays and Fault detectors. The numerical identifiers in Attachment A represent general device functions according to *ANSI/IEEE Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

The following provide additional information regarding the Protection System functions in Attachment A.

A “51 – AC inverse time overcurrent” relay connected to a CT on the neutral of a generator step-up transformer, referred to as “51N – AC Inverse Time Earth Overcurrent Relay (Neutral CT

Method)" in ANSI/IEEE Standard C37.2, would be included in a Protection System Coordination Study. Also applicable, are "51 – AC Inverse time overcurrent" relays connected to CTs on the phases of an autotransformer for through-fault protection. Overcurrent functions used in conjunction with other functions are to be reviewed as well. An example is a definite-time overcurrent function, which is a "50 – Instantaneous overcurrent" function used in conjunction with a "62 – Time-delay" function.

If the functions listed in Attachment A are used in conjunction with other functions, they would be included in a Protection System Coordination Study provided they require coordination with other Protection Systems. An example of this is a time-delayed "21 – Distance" function, which is a "21 – Distance" function with a "62 – Time-delay" function. Another example would be a definite-time overcurrent function, which is a "50 – Instantaneous overcurrent" function with a "62 – Time-delay" function. A "50 – Instantaneous overcurrent" function used for supervising a "21 – Distance" function would <u>not</u> be included in a Protection System Coordination Study as it does not require coordination with other Protection Systems.

Reviewing "21 – Distance" functions is limited to those applied for phase and ground distance where infeed is used in determining the phase or ground distance setting when zero-sequence mutual coupling is used in determining the setting. Where infeed is <u>not</u> used in determining the setting, "21 – Distance" functions would <u>not</u> be included in a Protection System Coordination Study, as the reach is not susceptible to changes in the magnitude of available short-circuit Fault current. Where infeed is used in determining the reach, coordination can be affected by changes in the magnitude of available short-circuit Fault current. Two examples where infeed may be used in determining the reach, are protection for a transmission line with a long tap and a three-terminal transmission line. Ground distance functions are influenced by zero-sequence mutual coupling. The ground distance measurement can appear to be greater than or less than the true distance to a Fault when there is zero-sequence mutual coupling. The influence of zero-sequence mutual coupling changes with the magnitude of available short-circuit current. Therefore, "21 – Distance" functions would be included in a Protection System Coordination Study, when zero-sequence mutual coupling is used in determining the setting.

The 67 – AC directional overcurrent function utilized in Protection Systems for Transmission lines can be instantaneous overcurrent, inverse time overcurrent, or both instantaneous overcurrent and inverse time overcurrent. For example, in a communication-aided directional comparison blocking (DCB) scheme, the instantaneous overcurrent function is set very sensitive. When a single line-to-ground Fault occurs on a Transmission line, the Fault is detected by a number of Protection Systems for other Transmission lines. Signals from communication equipment are transmitted and received to block the other Protection Systems for the non-faulted Transmission lines from operating, thereby providing the coordination. A 67 – AC directional overcurrent function used in a permissive overreaching transfer trip scheme (POTT) relies on a signal from the remote end to operate and, therefore, does not require coordination with other Protection Systems.

Instantaneous overcurrent and/or inverse time overcurrent for a 67 – AC directional overcurrent function are utilized in a non-communication-aided Protection System for Transmission lines. As communication is not used to prevent operation for Faults outside a Protection System's zone of protection, coordination is necessary with other Protection Systems for buses, transformers, and other Transmission lines. The instantaneous overcurrent function should be set to not overreach the end of the Transmission line. The inverse time overcurrent function should be set to coordinate with the inverse time overcurrent function of other Protection Systems. Changes in the magnitude of available Fault current can affect the coordination.

Requirement R3

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

The reliability objective of this requirement is for applicable entities to utilize the process established in Requirement R1. Utilizing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, decreases the possibility of introducing errors, and increases the likelihood of maintaining a coordinated Protection System.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes will be moved to this section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: "To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements~~for the purpose of detecting Faults on BES Elements and isolating those Faults~~, such that those Protection Systems operate in the intended sequence during Faults." PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii).

Completed Actions	Date
Standard Authorization Request (SAR) posted for comment	June 11 – July 10, 2007
SAR approved	August 13, 2007
Draft 1 of PRC-001-2 posted for comment	September 11 – October 26, 2009
Draft 1 of PRC-027-1 posted for formal comment with ballot	May 21 – July 5, 2012
Draft 2 of PRC-027-1 posted for formal comment with ballot	November 16 – December 17, 2012
Draft 3 of PRC-027-1 posted for formal comment with ballot	June 4 – July 3, 2013
Draft 4 of PRC-027-1 posted for formal comment with ballot	November 4 – December 31, 2013
Draft 5 of PRC-027-1 posted for informal comment	October 1 – October 21, 2014
Draft 5 of PRC-027-1 posted for formal comment with ballot	April 1 – May 15, 2015
Draft 6 of PRC-027-1 posted for formal comment with ballot	July 29 – September 11, 2015

Draft 6 of PRC-027-1 posted for 10-day final ballot.	October 5 – 14, 2015

Anticipated Actions	Date
~~10-day final ballot~~	~~October, 2015~~
NERC Board of Trustees (BOT) adoption	November, 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Protection System Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Protection System Issues Addressed by Other Reliability Standards:

Fault clearing is the only aspect of protection coordination addressed by Reliability Standard PRC-027-1. Including aspects of protection coordination other than Fault coordination would cause duplication or conflict with the requirements of other Reliability Standards. Specifically, other protection issues, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following Reliability Standards:

- Underfrequency Load shedding programs are addressed in PRC-006-2.
- Undervoltage Load shedding programs are addressed in PRC-010-1.
- Generator performance during declined frequency and voltage excursions is addressed in PRC-024-1.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-1.
- Transmission relay loadability is addressed in PRC-023-3.
- Generator relay loadability is addressed in PRC-025-1.
- Protective relay response during stable power swings is addressed in PRC-026-1.
- Protection System Misoperations (including those caused by coordination issues) are addressed in PRC-004-3.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Coordination of Protection Systems for Performance During Faults**
2. **Number:** PRC-027-1
3. **Purpose:** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1. Transmission Owner
   4.1.2. Generator Owner
   4.1.3. Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 below)
   4.2. Facilities: Protection Systems installed to detect and isolate Faults on BES Elements.
5. **Effective Date:** See the Implementation Plan for PRC-027-1, Project 2007-06 System Protection Coordination.

B. Requirements and Measures

Rationale for Requirement R1:

Coordinated Protection Systems enhance reliability by isolating faulted equipment, thus reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. The stated purpose of this standard is: "To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements~~for the purpose of detecting Faults on BES Elements and isolating those Faults~~, such that those Protection Systems operate in the intended sequence during Faults." Requirement R1 captures this intent by requiring responsible entities establish a process that, when followed, allows for their Protection Systems to operate in the intended sequence during Faults. Requirement R1, Parts 1.1 through 1.3 are key elements to the process for developing Protection System settings.

Part 1.1 Reviewing and updating the short-circuit model~~s~~ data used to develop new or revised Protection System settings helps to assure that settings are developed using accurate, up-to-date information. Generator Owners and Distribution Providers may not have or maintain short-circuit models; consequently, these entities would obtain the short-circuit model data from the Transmission Planners, Planning Coordinators, or Transmission Owners.

Part 1.2 A review of the developed Protection System settings reduces the likelihood of introducing human error and verifies that the settings produced meet the technical criteria of the entity. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of reviews.

Part 1.3 The coordination of Protection Systems associated with BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) is essential to the reliability of the BES. Communication and review of proposed settings among these entities are necessary to identify potential coordination issues and address the issues prior to implementation of any proposed Protection System changes.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

Unforeseen circumstances could require immediate changes to Protection System settings. Requirement R1, Part 1.3.4 requires owners to include ~~a procedure~~provisions to communicate those unplanned settings changes after-the-fact to the other owner(s) of the electrically ~~-~~joined Facilities.

Note: In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A review and update of short-circuit model~~s~~ data for the BES Elements under study.

1.2. A review of the developed Protection System settings.

1.3. For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.3.1. Provide the proposed Protection System settings to the owner(s) of the electrically~~-~~ joined Facilities.

1.3.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

1.3.3. Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

~~**1.3.4.**~~ Communicate with the other owner(s) of the electrically~~-~~ joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during~~:~~

~~**1.3.4.1.**~~ ~~Implementation~~ implementation or commissioning~~.~~

~~**1.3.4.2.**~~ , Misoperation investigations~~.~~

~~**1.3.4.3.**~~ ~~Maintenance~~, maintenance activities~~.~~

~~**1.3.4.4.**~~1.3.4. ~~Emergency~~, or emergency replacements required as a result of Protection System component failure.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity established a process to develop settings for its Protection Systems, in accordance with Requirement R1.

Rationale for Requirement R2:

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires ~~responsible entities (~~Transmission Owners, Generator Owners, and Distribution Providers~~)~~ to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. The numerical identifiers in Attachment A represent general protective device functions per ANSI/IEEE *Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Requirement R2 provides ~~responsible~~ entities with options to assess the state of their Protection System coordination.

Option 1 is a time-based methodology. The entity may choose to perform, at least once every six-calendar years, a Protection System Coordination Study for each of its ~~BES~~ Protection Systems identified ~~as being affected by changes in Fault current~~in Attachment

A. The six-calendar-year time interval was selected as a balance between the resources required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

Option 2 is a Fault current-based methodology. If Option 2 is initially selected, Fault current baseline(s) must be established prior to the effective date of this Reliability Standard. A baseline may be established when a new BES Element is installed or after a Protection System Coordination Study has been performed. The baseline(s) will be used as control point(s) for future Fault current comparisons. The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners ~~and~~, Planning Coordinators~~. At least once every~~, or Transmission Owners. In a time interval not to exceed six-calendar years following the effective date of this standard, ~~the~~an entity ~~will~~must perform a ~~Protection System Coordination Study when its~~ Fault current comparison. If the comparison identifies a deviation less than 15 percent, no further action is required for that six-year interval; however, if the comparison identifies a 15 percent or greater deviation in Fault current values (either three-phase or phase-to-ground) at each bus to which the BES Element is connected, the entity must also perform a Protection System Coordination Study during the same six-year interval. The baseline Fault current value(s) will be re-established whenever a new Protection System Coordination Study is performed. Fault current changes on the System not directly associated with BES modifications are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection System functions (identified in Attachment A of this standard) during Fault conditions. A Fault current deviation threshold of 15 percent or greater (as compared to the established baseline) and a maximum time interval of six calendar years were chosen for these evaluations. These parameters provide an entity with latitude to choose a Fault current threshold and time interval that best match its protection philosophy, Protection System maintenance schedule, or other business considerations, without creating risk to reliability (See the Supplemental Material section for more detailed discussion).

The footnote in Option 2 describes how an entity may change from a time-based option to a Fault current-based option for existing BES Elements ~~when~~as well as establishing baselines for new BES Elements by performing Protection System Coordination Studies. The footnote also ~~allows for~~ states that Fault current baselines for BES generating resources may be established at the ~~creation~~generator, the generator step-up (GSU) transformer(s), or at the common point of ~~a~~connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline ~~when a Protection System Coordination Study is performed for installing new Elements.~~may also be established at the BES aggregation point (total capacity greater than 75 MVA).

Option 3 provides the entity the choice of using both the time-based and Fault current-based methodologies. For example, the entity may choose to utilize the time-based methodology for Protection Systems at more critical Facilities and use the Fault current-based methodology for Protection Systems at other Facilities.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six-calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the BES Element is connected, all in a time interval not to exceed six-calendar years;[1] or,
- Option 3: Use a~~A~~ combination of the above.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity performed Protection System Coordination Study(ies) and/or Fault current comparisons in accordance with Requirement R2.

Rationale for Requirement R3:

Utilizing the processes established in Requirement R1 to develop new and revised Protection System settings provides a consistent approach to the development of Protection System settings and will minimize the potential for errors.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity utilized its settings development process established in Requirement R1, as specified in Requirement R3.

[1] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. The Fault current baseline for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA). If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity may establish the baseline by performing a Protection System Coordination Study.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance with Requirements R1, R2, and R3, and Measures M1, M2, and M3 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 or Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.3. OR The responsible entity failed to establish any process in accordance with Requirement R1.
R2.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3 but was late by less than or equal to 30 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 90 calendar days. OR The responsible entity failed to perform Option 1, Option

				2, or Option 3, in accordance with Requirement R2.
R3.	N/A	N/A	N/A	The responsible entity failed to utilize the process established in accordance with Requirement R1.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee – “Power Plant and Transmission System Protection Coordination.”

NERC System Protection and Control Task Force, December 7, 2006, “Assessment of Standard PRC-001-0 – System Protection Coordination.”

NERC System Protection and Control Task Force, September 2006, “The Complexity of Protecting Three-Terminal Transmission Lines.”

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	New standard developed under Project 2007-06

Attachment A

The following Protection System functions[2] are applicable to Requirement R2 if: (1) available Fault current levels are used to develop the settings for those Protection System functions~~:~~; and (2) those Protection System functions require coordination with other Protection Systems.

21 – Distance if:

- infeed is used in determining reach (phase and ground distance), or
- zero-sequence mutual coupling is used in determining reach (ground distance).

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent

67 – AC directional overcurrent if used in a non-communication-aided protection scheme

Notes:

1. The above Protection System functions ~~are susceptible to changes in the magnitude of available short-circuit Fault current. These functions~~ utilize current in their measurement to initiate tripping of circuit breakers. ~~The functions listed above are included in a Protection System Coordination Study because they require~~Changes in the magnitude of available Fault current can impact the coordination ~~with other Protection Systems.~~of these functions.
2. See the PRC-027-1 Supplemental Material section for additional information.

[2] ANSI/IEEE Standard C37.2 *Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Purpose

The Purpose states: To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.

Coordinated Protection Systems enhance reliability by isolating faulted equipment, reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. This standard requires that entities establish and implement a process to coordinate their ~~BES~~ Protection Systems to operate in the intended sequence during Faults.

Applicability

Transmission Owners, Generator Owners, and Distribution Providers are included in the Applicability of PRC-027-1 because they may own Protection Systems that are installed for the purpose of detecting Faults on the Bulk Electric System (BES). It is only those Protection Systems that are under the purview of this standard.

Transmission Owners are included in the Applicability of PRC-027-1 because they own the largest number of Protection Systems installed for the purpose of detecting Faults on the BES.

Generator Owners have Protection Systems installed for the purpose of detecting Faults on the BES. It is important that those Protection Systems are coordinated with Protection Systems owned by Transmission Owners to ensure that generation Facilities do not become disconnected from the BES unnecessarily. Functions such as impedance reaches, overcurrent pickups, and time delays need to be evaluated for coordination.

A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.

After the Protection Systems of Distribution Providers and Generator Owners are shown to be coordinated with other Protection Systems on the BES, there will be little future impact on the entities unless there are significant changes at or near the bus that interconnects with the Transmission Owner. The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current ~~availability~~data upon request by the Distribution Provider or Generator Owner. The Distribution Provider and Generator Owner will determine whether a change in Fault current from the baseline has occurred such that a review of coordination is necessary.

Requirement R1

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults.

The reliability objective of this requirement is to have applicable entities establish a process to develop settings for coordinating their ~~BES~~ Protection Systems, such that they operate in the intended sequence during Faults. The parts that are included as elements of the process ensure the development of accurate settings, as well as providing internal and external checks to minimize the possibility of errors that could be introduced in the development of settings.

This standard references various publications that discuss protective relaying theory and application. The description of "coordination of protection" is from the pending revision of IEEE Standard C37.113-1999 (Reaffirmed: 2004), *Guide for Protective Relay Applications to Transmission Lines*, which reads:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Entities may have differing technical criteria for the development of Protection System settings based on their own philosophies. These philosophies can vary based on system topology, protection technology utilized, as well as historical knowledge; as such, a single definition or criterion for "Protection System coordination" is not practical.

The coordination of some Protection Systems may seem unnecessary, such as for a line that is protected solely by dual current differential relays. However, backup Protection Systems that are enabled to operate based on current or apparent impedance with some definite or inverse time delay must be coordinated with other Protection Systems of the BES Element such that tripping does not unnecessarily occur for Faults outside of the differential zone.

Part 1.1 A review and update of short-circuit model~~s~~ data for the BES Elements under study.

The short-circuit study provides the necessary Fault currents used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers ~~is the short-circuit study.~~. Generator Owners and Distribution Providers may not have or maintain short-circuit models; consequently, these entities would obtain the short-circuit model data from the Transmission Planners, Planning Coordinators, or Transmission Owners. Including a review and, if necessary, an update of short-circuit study information is necessary to ensure that information accurately reflects the physical power system that will form the basis of the Protection System Coordination Study and development of Protection System relay settings. The results of a short-circuit study are only as accurate as the information that its calculations are based on.

A short-circuit study is an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical Fault. Because the results of short-circuit studies are used as the basis for protective device coordination studies, the short-circuit model should accurately reflect the physical power system.

Reviews could include:

1. A review of applicable BES line, transformer, and generator impedances and Fault currents.
2. A review of the network model to confirm the network in the study accurately reflects the configuration of the actual System, or how the System will be configured when the proposed relay settings are installed.
3. A review, where applicable, of interconnected Transmission Owner, Generator Owner, and Distribution Provider information.

Part 1.2 A review of the developed Protection System settings.

A review of the Protection System settings prior to implementation reduces the possibility of introducing human error. A review is any systematic process of verifying the developed settings meet the technical criteria of the entity. Examples of reviews include peer reviews, automated checking programs, and entity-developed review procedures.

Part 1.3 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

Requirement R1, Part 1.3 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities. Communication among these entities is essential so potential Protection System coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

Part 1.3.1 1.3.1. Provide the proposed Protection System settings to the owners of the electrically~~-~~ joined Facilities.

Requirement R1, Part 1.3.1 requires the entity to include in its process a provision to provide proposed Protection System settings to other entities. This communication ensures that the other entities have the necessary information to review the settings and determine if there are any Protection System coordination issues.

Part 1.3.2 Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

Requirement R1, Part 1.3.2 requires the entity receiving proposed Protection System settings to include in its process a provision to respond to the entity that initiated the proposed changes. This ensures that the proposed settings are reviewed and that the initiating entity receives a response indicating Protection System coordination issues were identified, or affirmation that no issues were identified.

Part 1.3.3 Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Requirement R1, Part 1.3.3 requires the entity to include in their process a provision to verify that any identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation. This ensures that any potential impact to BES reliability is minimized.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

Note: There could be instances where coordination issues are identified and the entities agree not to mitigate all of the issues based on engineering judg~~e~~ment. It is also recognized that coordination issues identified during a project may not be immediately resolved if the resolution involves additional system modifications not identified in the initial project scope. Further, there could be situations where protection philosophies differ between entities, but the entities can agree that these differences do not create coordination issues.

Part 1.3.4 Communicate with the other owner(s) of the electrically~~-~~ joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during~~:~~

~~**1.3.4.1.** Implementation~~ implementation or commissioning~~.~~

~~**1.3.4.2.**~~ , Misoperation investigations~~.~~

~~**1.3.4.3.** Maintenance~~, maintenance activities~~.~~

~~**1.3.4.4.** Emergency~~, or emergency replacements required as a result of Protection System component failure.

Requirement R1, Part 1.3.4 requires the entity to communicate revisions to Protection System settings that occur due to unforeseen circumstances and differ from those developed during the planning stages of projects.

Requirement R2

This requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A:

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six-calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase

or phase to ground) at a bus to which the BES Element is connected, all in a time interval not to exceed six-calendar years;[3] or,

- Option 3: Use a~~A~~ combination of the above.

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. Two triggers were established for initiating a review of existing Protection System settings to allow for industry flexibility.

In the first option, an entity may choose a time-based methodology to review Protection System settings, thus eliminating the necessity of establishing a Fault current baseline and periodically performing Fault current comparisons. This option provides the entity the flexibility to choose an interval of up to six-calendar years for performing the Protection System Coordination Studies for those Protection System functions in Attachment A. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which ~~an~~a BES Element is connected. Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators, or Transmission Owners. This option allows the entity to choose an interval of up to six-calendar years to perform the Fault current comparisons and Protection System Coordination Studies. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. A maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) was established based on generally-accepted margins for setting Protection Systems in which incremental Fault current changes would not interfere with coordination. The 15 percent maximum deviation provides an entity with latitude to choose a Fault current threshold that best matches its protection philosophy, or other business considerations. The Fault current based option requires an entity to first establish a Fault current baseline to be used as a point of reference for future Fault current studies. The Fault current values used in the percent change calculation, whether three-phase or phase-to-ground Fault

[3] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. The Fault current baseline for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA). If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity may establish the baseline by performing a Protection System Coordination Study.

currents, are typically determined with all generation in service and all transmission BES Elements in their normal operating state.

~~An~~As described in the footnote for Requirement R2, Option 2, an entity that elects to initially use Option 2 ~~following the effective date of the standard,~~ must establish its baseline prior to the effective date of the standard. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity may establish the baseline upon performing a Protection System Coordination Study. The Fault current ~~values used in the original~~ baseline values can be updated or ~~created~~established when a Protection System Coordination Study is performed. The baseline values at each bus to which ~~an~~a BES Element is connected are updated whenever a new Protection System Coordination Study is performed for the subject Protection System. The footnote also states that the Fault current baselines may be established for BES generating resources at the generator, the BES aggregation point for dispersed power producing resources, or at the common point of connection at 100 kV or above.

> **Example:** ~~An~~Prior to the effective date of PRC-027-1, an entity intending to use Option 2 of Requirement R2 establishes an initial baseline ~~is established at~~ ; e.g., 10,000 amps~~.~~ ~~During the first~~ at the bus to which the BES Element under study is connected. A short-circuit review~~, it is discovered~~ performed on March 1, 2024, for example, identifies that the Fault current has increased to 11,250 amps (12.5 percent deviation~~change~~); consequently, no Protection System Coordination Study is required since the increase is below the maximum 15 percent deviation. The baseline value for the next ~~study~~comparison (to be performed no later than December 31, 2030) remains at 10,000 amps because no study was ~~performed. However, during~~required as a result of the initial comparison. During the next six-year interval, Fault current comparison~~,~~ identifies that the Fault current has increased to 11,500 (15 percent deviation~~change~~); therefore, a Protection System Coordination Study is required~~,~~ (and must also be completed no later than December 31, 2030), and a new baseline of 11,500 amps would be established.
>
> **Note:** In the first review described above, if the entity decides to perform a Protection System Coordination Study at the 12.5 percent deviation and the results of the study indicate that the settings still meet the setting criteria of the entity, then no settings changes are required and the baseline Fault current(s) would be updated.

As a third option, an entity has the flexibility to apply a combination of the two methodologies. For example, an entity may choose the periodic Protection System review (Option 1) and review its Facilities operated above 300 kV on a six-calendar-year interval, while choosing to use the Fault current comparison (Option 2) for its Facilities operated below 300 kV.

~~Attachment A identifies the~~ The Protection System functions listed in Attachment A utilize AC current in their measurement to initiate tripping of circuit breakers and the coordination of these functions is susceptible to changes in the magnitude of available short-circuit Fault current. These functions ~~utilize AC current in their measurement to initiate tripping of circuit breakers~~are included in Attachment A based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. Examples of functions not included in Attachment A because they do not meet both of the criteria are differential relays and Fault detectors. The numerical identifiers in Attachment A represent general device functions according to *ANSI/IEEE Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.~~ The device functions listed in Attachment A are to be reviewed provided they require coordination with other Protection Systems. The following scenarios provide some examples for applying Attachment A.~~

The following provide additional information regarding the Protection System functions in Attachment A.

A "51 – AC inverse time overcurrent" relay connected to a CT on the neutral of a generator step-up transformer, referred to as "51N – AC Inverse Time Earth Overcurrent Relay (Neutral CT Method)" in ANSI/IEEE Standard C37.2, would be included in a Protection System Coordination Study. Also applicable, are "51 – AC Inverse time overcurrent" relays connected to CTs on the phases of an autotransformer for through-fault protection. Overcurrent functions used in conjunction with other functions are to be reviewed as well. An example is a definite-time overcurrent function, which is a "50 – Instantaneous overcurrent" function used in conjunction with a "62 – Time-delay" function.

If the functions listed in Attachment A are used in conjunction with other functions, they would be included in a Protection System Coordination Study provided they require coordination with other Protection Systems. An example of this is a time-delayed "21 – Distance" function, which is a "21 – Distance" function with a "62 – Time-delay" function. Another example would be a definite-time overcurrent function, which is a "50 – Instantaneous overcurrent" function with a "62 – Time-delay" function. A "50 – Instantaneous overcurrent" function used for supervising a "21 – Distance" function would not be included in a Protection System Coordination Study as it does not require coordination with other Protection Systems.

Reviewing "21 – Distance" functions is limited to those applied for phase and ground distance where infeed is used in determining the phase or ground distance setting when zero-sequence mutual coupling is used in determining the setting. Where infeed is not used in determining the setting, "21 – Distance" functions would not be included in a Protection System Coordination Study, as the reach is not susceptible to changes in the magnitude of available short-circuit Fault current. Where infeed is used in determining the reach, coordination can be affected by changes in the magnitude of available short-circuit Fault current. Two examples where infeed may be used in determining the reach, are protection for a transmission line with a long tap and a three-terminal transmission line. Ground distance functions are influenced by zero-sequence mutual coupling. The ground distance measurement can appear to be greater than or less than the true distance to a Fault when there is zero-sequence mutual coupling. The influence of zero-sequence mutual coupling changes with the magnitude of available short-circuit current. Therefore, "21 – Distance" functions would be included in a Protection System Coordination Study, when zero-sequence mutual coupling is used in determining the setting.

The 67 – AC directional overcurrent function utilized in Protection Systems for Transmission lines can be instantaneous overcurrent, inverse time overcurrent, or both instantaneous overcurrent and inverse time overcurrent. For example, in a communication-aided directional comparison blocking (DCB) scheme, the instantaneous overcurrent function is set very sensitive. When a single line-to-ground Fault occurs on a Transmission line, the Fault is detected by a number of Protection Systems for other Transmission lines. Signals from communication equipment are transmitted and received to block the other Protection Systems for the non-faulted Transmission lines from operating, thereby providing the coordination. A 67 – AC directional overcurrent function used in a permissive overreaching transfer trip scheme (POTT) relies on a signal from the remote end to operate and, therefore, does not require coordination with other Protection Systems.

Instantaneous overcurrent and/or inverse time overcurrent for a 67 – AC directional overcurrent function are utilized in a non-communication-aided Protection System for Transmission lines. As communication is not used to prevent operation for Faults outside a Protection System's zone of protection, coordination is necessary with other Protection Systems for buses, transformers, and other Transmission lines. The instantaneous overcurrent function should be set to not overreach the end of the Transmission line. The inverse time overcurrent function should be set to coordinate with the inverse time overcurrent function of other Protection Systems. Changes in the magnitude of available Fault current can affect the coordination.

Requirement R3

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

The reliability objective of this requirement is for applicable entities to utilize the process established in Requirement R1. Utilizing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, decreases the possibility of introducing errors, and increases the likelihood of maintaining a coordinated Protection System.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes will be moved to this section.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-06 System Protection Coordination

Approvals Requested

- PRC-027-1 – Coordination of Protection Systems for Performance During Faults

Retirements Requested

- PRC-001-1.1(ii) – System Protection Coordination[1]

Prerequisite Approvals (for Retirements Requested)

- TOP-009-1 – Knowledge of Composite Protection Systems and Remedial Action Schemes and Their Effects

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 of PRC-027-1)

New or Modified Term(s) for Glossary of Terms Used in NERC Reliability Standards

Protection System Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Effective Date of New or Revised Standards

PRC-027-1 – Coordination of Protection Systems for Performance During Faults

Reliability Standard PRC-027-1 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar

[1] The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of both proposed Reliability Standards PRC-027-1 and TOP-009-1. NERC is proposing the complete retirement of PRC-001-1.1(ii) in the implementation plans associated with both PRC-027-1 and TOP-009-1. The Project 2007-06 System Protection Coordination Mapping Document shows how PRC-027-1 addresses requirements R3 and R4 of PRC-001-1.1(ii). The remaining requirements of PRC-001-1.1(ii) – Requirements R1, R2, R5, and R6 are proposed for retirement in Project 2007-6.2 Phase 2 of System Protection Coordination (see the Mapping Document for Project 2007-06.2 Phase 2 of System Protection Coordination).

quarter that is twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Effective Date for New or Modified NERC Glossary Terms

The NERC Glossary Term “Protection System Coordination Study” shall become effective on the effective date for PRC-027-1.

Retirements

PRC-001-1.1(ii) – System Protection Coordination

PRC-001-1.1(ii) – System Protection Coordination shall be retired at midnight of the day immediately prior to the day that TOP-009-1 and PRC-027-1 become effective.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Implementation Plan

Project 2007-06 System Protection Coordination

Approvals Requested

- PRC-027-1 – Coordination of Protection Systems for Performance During Faults

Retirements Requested

- PRC-001-1.1(ii) – System Protection Coordination[1]

Prerequisite Approvals (for Retirements Requested)

- TOP-009-1 – Knowledge of Composite Protection Systems and Remedial Action Schemes and Their Effects

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 of PRC-027-1)

New or Modified Term(s) for Glossary of Terms Used in NERC Reliability Standards

Protection System Coordination Study

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Effective Date of New or Revised Standards

PRC-027-1 – Coordination of Protection Systems for Performance During Faults

Reliability Standard PRC-027-1 shall become effective on the first day of the first calendar quarter that is ~~twelve (12~~twenty-four (24) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first

[1] The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of both proposed Reliability Standards PRC-027-1 and TOP-009-1. NERC is proposing the complete retirement of PRC-001-1.1(ii) in the implementation plans associated with both PRC-027-1 and TOP-009-1. The Project 2007-06 System Protection Coordination Mapping Document shows how PRC-027-1 addresses requirements R3 and R4 of PRC-001-1.1(ii). The remaining requirements of PRC-001-1.1(ii) – Requirements R1, R2, R5, and R6 are proposed for retirement in Project 2007-6.2 Phase 2 of System Protection Coordination (see the Mapping Document for Project 2007-06.2 Phase 2 of System Protection Coordination).

calendar quarter that is ~~twelve (12~~twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Effective Date for New or Modified NERC Glossary Terms

The NERC Glossary Term "Protection System Coordination Study" shall become effective on the effective date for PRC-027-1.

Retirements

PRC-001-1.1(ii) – System Protection Coordination

PRC-001-1.1(ii) – System Protection Coordination shall be retired at midnight of the day immediately prior to the day that TOP-009-1 and PRC-027-1 become effective.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Final Ballot Open through October 14, 2015

Now Available

A final ballot for **PRC-027-1 – Coordination of Protection Systems for Performance During Faults** is open through **8 p.m. Eastern, Wednesday, October 14, 2015.**

Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a vote. All ballot pool members may change their previously cast vote. A ballot pool member who failed to vote during the previous ballot period may vote in the final ballot period. If a ballot pool member does not participate in the final ballot, the member's vote from the previous ballot will be carried over as their vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard here. If you experience any difficulties using the Standards Balloting & Commenting System (SBS), contact Wendy Muller.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at EROhelpdesk@nerc.net (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The voting results for the standard will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption. Once TOP-009-1 is approved by ballot and adopted by the Board of Trustees, PRC-027-1 will be filed with the appropriate regulatory authorities in conjunction with TOP-009-1 to achieve the complete retirement of PRC-001-1.1(ii).

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

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Standards Announcement

Project 2007-06 System Protection Coordination
PRC-027-1

Final Ballot Results

Now Available

A final ballot for **PRC-027-1 – Coordination of Protection Systems for Performance During Faults** concluded **8 p.m. Eastern, Wednesday, October 14, 2015.**

The standard received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides detailed results for the ballot.

Ballot
Quorum / Approval
89.16% / 80.94%

Next Steps

The standard will be submitted to the Board of Trustees for adoption. Once TOP-009-1 (Project 2007-06.2) is approved by ballot and adopted by the Board of Trustees, PRC-027-1 will be filed with the appropriate regulatory authorities in conjunction with TOP-009-1 to achieve the complete retirement of PRC-001-1.1(ii).

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

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BALLOT RESULTS

Ballot Name: 2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) FN 3 ST
Voting Start Date: 10/5/2015 11:55:07 AM
Voting End Date: 10/14/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 296
Total Ballot Pool: 332
Quorum: 89.16
Weighted Segment Value: 80.94

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	82	1	55	0.786	15	0.214	0	3	9
Segment: 2	8	0.5	4	0.4	1	0.1	0	2	1
Segment: 3	81	1	55	0.797	14	0.203	0	4	8
Segment: 4	29	1	15	0.714	6	0.286	0	2	6
Segment: 5	74	1	44	0.721	17	0.279	0	5	8
Segment: 6	46	1	33	0.805	8	0.195	0	1	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	2	0.2	2	0.2	0	0	0	0	0
Segment:	8	0.8	8	0.8	0	0	0	0	0

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10									
Totals:	332	6.7	218	5.423	61	1.277	0	17	36

BALLOT POOL MEMBERS

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		Negative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Negative	N/A
1	Beaches Energy Services	Don Cuevas		None	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Abstain	N/A

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1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		Negative	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Negative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis	marcus lotto	None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Greg Davis	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A

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1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	Iberdrola - Central Maine Power Company	Joe Turano		Affirmative	N/A
1	IDACORP - Idaho Power Company	Johnny Anderson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Meghan Ferguson	Affirmative	N/A
1	JEA	Ted Hobson	Thomas McElhinney	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	N/A
1	Long Island Power Authority	Robert Ganley		Negative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

1	NB Power Corporation	Alan MacNaughton		Negative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Negative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Affirmative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	John Walker		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Negative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A

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1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Negative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Illinois Power Cooperative	William Hutchison		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Negative	N/A
2	California ISO	Richard Vine		Abstain	N/A

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2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula	Mark Wilson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Negative	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Bartow, Florida	Matt Culverhouse		Negative	N/A

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3	City of Garland	Ronnie Hoeinghaus		None	N/A
3	City of Green Cove Springs	Mark Schultz		None	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Bill Hughes	Mary Downey	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Negative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Charles Morgan		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	CPS Energy	Brian Bartos		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Negative	N/A
3	Duke Energy	Lee Schuster		Negative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Cindy Stewart	Richard Hoag	Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy -	Jessica Tucker		Affirmative	N/A

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	Kansas City Power and Light Co.				
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Mace Hunter		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Northeast Utilities	Mark Kenny		Affirmative	N/A

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3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		Negative	N/A
3	Pacific Gas and Electric Company	John Hagen		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		None	N/A
3	PNM Resources	Michael Mertz		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		Abstain	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Negative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	N/A
3	Sho-Me Power Electric	Jeff Neas		Affirmative	N/A

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	Cooperative				
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-County Electric Cooperative, Inc.	Chris Giles		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	We Energies - Wisconsin Electric Power Marketing	Jim Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Negative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	City of Clewiston	Lynne Mila		None	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		None	N/A
4	City of Redding	Nick Zettel	Mary Downey	Affirmative	N/A
4	City of Winter Park	Mark Brown		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A

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4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Negative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Flathead Electric Cooperative	Russ Schneider		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		None	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	None	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		Negative	N/A
4	North Carolina Electric Membership Corporation	John Lemire	Scott Brame	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Negative	N/A

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4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Abstain	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon	brian robinson	Negative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski	Matthew Beilfuss	None	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	N/A
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Abstain	N/A
5	City and County of San Francisco	Daniel Mason		Abstain	N/A
5	City of Garland	[illegible]		None	N/A

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5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Mary Downey	Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Negative	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Negative	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Essential Power, LLC	Gerry Adamski		Negative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Golden Spread	Chip Koloini	Sara Bednar	None	N/A

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	Electric Cooperative, Inc.				
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne	manon paquet	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Affirmative	N/A

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5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Bernard Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	N/A
5	Oxy - Ingleside Cogeneration LP	Michelle D'Antuono		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Barbara Croas		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		None	N/A
5	Seattle City Light	Mike Haynes		Negative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Abstain	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A

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5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		Negative	N/A
5	Z_NA	Replacementvoter-Dan Wilson		Affirmative	N/A
6	ACES Power Marketing	Ben Engelby		None	N/A
6	AEP - AEP Marketing	Dan Ewing		Negative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Mary Downey	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A

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6	Exelon	Maggy Powell		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges		Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	N/A
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik	Simon Tanapat	Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
6	Omaha Public Power District	Mark Trumble		None	N/A

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6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Negative	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham	Chris Janick	Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Negative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Abstain	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability	Peter Heidrich		Affirmative	N/A

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	Coordinating Council				
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Exhibit G-2

Summary of Development History and Record of Development for Project 2007-06.2 Phase 2 of System Protection Coordination

Summary of Development History for Project 2007-06.2 Phase 2 of System Protection Coordination

Summary of Development History

The development record for proposed Reliability Standard PER-006-1 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team selected to lead each project in accordance with Section 4.3 if the NERC Standards Process Manual.[2] For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in **Exhibit H**.

II. Standard Development History

A. Standard Authorization Request Development

To address a FERC directive in Order No. 693[3], a Standard Authorization Request was approved by the Standards Committee and posted in Project 2007-06 for a 30-day informal comment period from June 11, 2007 through July 10, 2007. In conjunction with Project 2007-06 System Protection Coordination (Phase 1), a subsequent Phase 2 of System Protection Coordination was initiated in 2015 to address the remaining Requirements R1, R2, R5, and R6 of PRC-001-1.1(ii).

---

1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

2 The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

3 Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*, 72 Fed. Reg. 16416 (2007) (to be codified at 18 C.F.R. pt. 40).

B. First Posting – Formal Comment Period, Initial Ballot and Non-Binding Poll

Proposed Reliability PER-006-1[4] was posted for a 45-day formal comment period from March 10, 2016 through April 25, 2016, with an initial ballot held from April 15, 2016 through April 25, 2016. Several documents were posted for guidance with the first draft, including the Unofficial Comment Form, Mapping Document, the Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") Justification document, and the Evaluation of Definition Impacts to Reliability Standards document. The initial ballot received 83.67% quorum, and 80.57% approval. The Non-binding Poll for VRFs and VSLs reached quorum at 80.73% of the ballot pool, and the standard and associated documents received support from 71.43% of the voters. There were 54 sets of responses to the posting, including comments from approximately 126 different individuals from approximately 93 companies representing 8 of the 10 of the industry segments.[5]

C. Final Ballot

Proposed Reliability Standard PER-006-1 was posted for a 10-day final ballot period from May 17, 2016 through May 26, 2016. The ballot for the proposed Reliability Standard and associated documents reached quorum at 88.96% of the ballot pool, and the standard received sufficient affirmative votes for approval, receiving support from 82.52% of the voters.[6]

---

[4] The standard drafting team ("SDT") initially authorized TOP-009-1 for posting to address the reliability objective of Requirement R1. However, industry comments from the initial and subsequent formal postings of TOP-009-1, led the SDT to alter its approach. The SDT decided to address the reliability objective through a Personnel Performance, Training, and Qualifications ("PER") Reliability Standard and developed PER-006-1.

[5] NERC, *Consideration of Comments*, Project 2007-06.2, Phase 2 of System Protection Coordination, (May 17, 2016), *available at* http://www.nerc.com/pa/Stand/Project200706_2SystemProtectionCoordinationDL/2007_06_2_Consideration_of_Comments_2016_05_17.pdf.

[6] NERC, *Standards Announcement*, Project 2007-06.2 Phase 2 of System Protection Coordination, *available at* http://www.nerc.com/pa/Stand/Project200706_2SystemProtectionCoordinationDL/2007-06.2_FB_Results_Word_Announce_05272016.pdf.

D. Board of Trustees Adoption

Proposed Reliability Standard PER-006-1 was adopted by the NERC Board of Trustees on August 11, 2016.[7]

[7] NERC, *Board of Trustees Agenda Package*, Agenda Item 6a (Project 2007-06.2 Phase 2 of System Protection Coordination (PER-006-1)), *available at* http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_August_11_2016_Pkg.pdf.

Complete Record of Development for Project 2007-06.2 Phase 2 of System Protection Coordination

Project 2007-06.2 Phase 2 of System Protection Coordination

Related Files | 2007-06 System Protection Coordination

Status
Final ballots for **PER-006-1 – Specific Training for Personnel** and the modified definitions of **"Operational Planning Analysis" (OPA)** and **"Real-time Assessment"(RTA)** concluded **8 p.m. Eastern, Thursday, May 26, 2016.** The voting results for the standard and definitions can be accessed via the links below. The standard and definitions will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Retirement of PRC-001-1.1(ii)
In conjunction with Project 2007-06 System Protection Coordination (Phase 1), NERC is proposing the complete retirement of PRC-001-1.1(ii). Requirements R1, R2, R5, and R6 are proposed for retirement in Project 2007-6.2 Phase 2 of System Protection Coordination. See the Mapping Document below for an explanation of how the reliability objectives of those requirements are addressed by other standards, the proposed PER-006-1 (*Specific Training for Personnel*), and the definition modifications to "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA). The remaining two Requirements R3 and R4 of PRC-001-1.1(ii) are addressed by PRC-027-1 (*Coordination of Protection Systems for Performance During Faults*). For details for Phase 1 are found on the 2007-06 project page. The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of Reliability Standards PRC-027-1 and the proposed PER-006-1 and definition modifications under Phase 2. NERC is proposing the retirement of PRC-001-1.1(ii) in the implementation plans associated with both projects.

Background
Phase 1 (2007-06)
The System Protection Coordination Standard Drafting Team developed a new Reliability Standard, PRC-027-1 to address coordination of Protection System performance during Faults. This standard incorporates and clarifies the Protection System coordination aspects of Requirements R3 and R4 contained in PRC-001-1.1 that is proposed for complete retirement.

Phase 2 (2007-06.2)
Phase 2 is addressing the remaining Requirements R1, R2, R5, and R6 of PRC-001-1.1(ii). See the Mapping Document for a complete explanation on how the reliability objectives of Requirements R1, R2, R5, and R6 are addressed by other standards, the modified definitions of OPA and RTA, and the proposed PER-006-1 Reliability Standard.

Standard(s) Affected: PER-006-1 - Specific Training for Personnel, Retirement of PRC-001-1.1 (ii) - System Protection Coordination

Purpose / Industry Need
Protection System coordination among registered owners of the Protection Systems associated with Interconnected Elements is key to the reliability of the Bulk Electric System.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft PER-006-1 Clean **(30)**| Redline to Last Posted **(31)** PRC-001-1.1 (ii) Redline to Last Approved **(32)** Definitions of “Operational Planning Analysis” and “Real-time Assessment” Clean **(33)**| Redline to Last Posted **(34)** Implementation Plan Clean **(35)**| Redline to Last Posted **(36)** **Supporting Materials** Mapping Document Clean **(37)**| Redline to Last Posted **(38)** VRF/VSL Justification **(39)** Evaluation of Definition Impacts to Reliability Standards Clean **(40)**| Redline to Last Posted **(41)**	Final Ballots Info **(42)** Vote	05/17/16 - 05/26/16	Summary **(43)** Ballot Results Standard **(44)** Definitions **(45)**	

Draft 1 PER-006-1 **(12)** PRC-001-1.1 (ii) Redline to Last Approved **(13)** Definitions (“Operational Planning Analysis” and “Real-time Assessment”) **(14)** Implementation Plan **(15)** **Supporting Materials** Unofficial Comment Form (Word) **(16)** VRF/VSL Justification **(17)** Mapping Document **(18)** Evaluation of Definition Impacts to Reliability Standards **(20)**	Initial Ballots and Non-binding Poll Updated Info **(21)** Info **(22)** Vote	04/15/16 - 04/25/16	Summary **(24)** Ballot Results Standard **(25)** Definitions **(26)** Non-binding Poll Results **(27)**	
	Comment Period Info **(23)** Submit Comments	03/10/16 - 04/25/16	Comments Received **(28)**	Consideration of Comments **(29)**
	Join Ballot Pools If you had previously joined the ballot pools for this project, you **must** join these new ballot pools to cast votes. Ballot pool members from previous ballots for 2007-06.2 **will not** be carried over to these ballot pools.	03/10/16 - 04/08/16		
		03/24/16 - 04/25/16		

Draft Reliability Standard Audit Worksheet (RSAW)	Info Send RSAW feedback to: RSAWfeedback@nerc.net			
Standard Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(10)**	Nomination Period Info **(11)** Submit Nominations	01/26/16 - 02/09/16		
Draft 2 TOP-009-1 Clean | Redline to Last Posted Implementation Plan Clean | Redline to Last Posted **Supporting Materials** Unofficial Comment Form (Word) Mapping Document Clean | Redline to Last Posted	Additional Ballot and Non-binding Poll Updated Info Info Vote	11/10/15 - 11/19/15	Summary Ballot Results Non-binding Poll Results	
	Comment Period Info Submit Comments	10/06/15 - 11/19/15	Comments Received	Consideration of Comments

VRF/VSL Justification Clean | Redline to Last Posted Draft Reliability Standard Audit Worksheet (RSAW)	Info Send RSAW feedback to: RSAWfeedback@nerc.net	10/20/15 - 11/19/15		
Draft 1 TOP-009-1 PRC-001-1.1 (ii) Redline to Last Approved Implementation Plan **Supporting Materials** Unofficial Comment Form (Word) Mapping Document VRF/VSL Justification	Initial Ballot and Non-binding Poll Updated Info Info Vote	09/02/15 - 09/11/15	Summary Ballot Results Non-binding Poll Results	
	Comment Period Info Submit Comments	07/29/15 - 09/11/15	Comments Received	Consideration of Comments
	Join Ballot Pools	07/29/15 - 08/27/15		
	Info	08/12/15 - 09/11/15		

Draft RSAW	Send RSAW feedback to: RSAWfeedback@nerc.net			
Nominations for Standard Drafting Team **Supporting Materials** Nomination Form (Word) **(8)**	Nomination Period Info **(9)** Submit Nomination	01/06/15 - 01/20/15		
Project 2007-06 System Protection Coordination (Phase 1) Reference Material				
Final Standard Authorization Request (SAR) Clean **(6)**| Redline **(7)**				
Draft SAR Version 1 System Protection Coordination Draft SAR Version 1 **(1)** **Supporting Materials** NERC SPCTF Assessment of Standard PRC-001-0 – System	Comment Period Info **(3)** Submit Comments	6/11/2007 - 7/10/2007	Comments Received **(4)**	Consideration of Comments **(5)**

Protection Coordination **(2)**				

Standard Authorization Request Form

Title of Proposed Standard	**PRC-001-1 — System Protection Coordination (Project 2007-06)**
Request Date	May 7, 2007

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)
Name NERC System Protection and Control Task Force (Attachment A)	☐	New Standard
Primary Contact Charles Rogers (SPCTF Chairman)	☒	Revision to existing Standard
Telephone 517-788-0027 Fax 517-788-0917	☐	Withdrawal of existing Standard
E-mail cwrogers@cmsenergy.com	☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

The purpose of standard PRC-001-1 — System Protection Coordination should remain "To ensure system protection is coordinated among operating entities." The standard should be revised to:

1. Assure that Protection System application and performance issues are coordinated among all related entities.
2. Correct the applicable entities within the standard to reflect the actual functional responsibilities, as described in the NERC Functional Model.
3. Incorporate other general improvements described in the standards development work plan and from other sources.
4. Address directives received from ERO regulatory authorities.
5. Consider the observations and recommendations developed by the NERC SPCTF, which are detailed in the attached report (Attachment B), approved by the Planning Committee in December 2006.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

Protection system coordination is an absolute necessity for the North American electric system to operate properly. PRC-001 is a Version 0 standard, and was translated from an operating policy that was appropriate in an era of voluntary compliance.

The Version 0 standards and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update those standards, incorporating improvements to make the standards more suitable for enforcement.

Both FERC (within Order 693) and the SPCTF (in their report on PRC-001) identified significant shortcomings in the existing standard.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

The existing PRC-001 Standard has been identified in the Reliability Standards Development Plan as requiring revision, within the FERC Order 693 as requiring revisions, and by a SPCTF report (attached) which identified a number of issues with the existing standard (the SPCTF report, which precedes FERC Order 693, also includes observations from the preceding FERC NOPR on RM-06-16-000). This revision of PRC-001 should address concerns from these sources and should include the upgrades to the standard identified in Attachment C to bring the revised standard into conformance with the latest version of the ERO Rules of Procedure.

Detailed Description

This project will address the issues identified by the System Protection and Control Task Force for the planning-related requirements in PRC-001 as well as any planning-related concerns identified in FERC Order 693. (The operations-related requirements in PRC-001 are being addressed under Project 2006-06.) A detailed listing of the areas of the existing standard that need improvement is provided in Attachment B titled "NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination"

The drafting team will also make the improvements to the standard identified in Attachment C – "Reliability Standards Review Guidelines" to bring the revised standard into conformance with the latest version of the ERO Rules of Procedure.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☒	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes

5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	**Explanation**
MOD-011-0	Modify to include the essential data for wide-area fault studies, as noted in the attached SPCTF report on PRC-001.

Related SARs

SAR ID	**Explanation**
RC SAR	Project 2006-06 – Reliability Coordination includes modification of the real-time requirements but does not address the planning-related requirements.

Regional Variances

Region	**Explanation**
ERCOT	None
FRCC	None
MRO	None
NPCC	None
SERC	None
RFC	None
SPP	None
WECC	None

NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination

December 7, 2006

A Technical Review of Standards

Prepared by the
System Protection and Controls Task Force
of the
NERC Planning Committee

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Appendix B — SYSTEM PROTECTION AND CONTROL TASK FORCE **9**

This report was approved by the Planning Committee on December 7, 2006, for forwarding to the Standards Committee.

Introduction

When the original scope for the System Protection and Control Task Force was developed, one of the assigned items was to review all of the existing PRC-series Reliability Standards, to advise the Planning Committee of our assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.

This report presents the SPCTF's assessment of PRC-001-0 – System Protection Coordination. The report includes the SPCTF's understanding of the intent of this standard and contains specific observations relative to the existing standard.

This standard was developed by translating the requirements of an earlier Phase I Planning Standard; thus it has not been previously subjected to a critical review of the Requirements.

Executive Summary

This reliability standard is intended to assure that system protection is coordinated between multiple transmission entities and between generation entities and transmission entities. It appears that this standard is intended to address coordination of protection functions and capabilities in both the operating time frame and the planning time frame. These time frames, as they apply to protective functions, are discussed, as are the various responsibilities to assure the related coordination.

The SPCTF concludes that the list of applicable entities in the existing standard is incomplete and that the assigned responsibilities do not reflect the activities of the identified functions. Significantly, the existing standard disregards the significant responsibilities and roles of the equipment owners; specifically, the Transmission Owners and Generator Owners.

The SPCTF also concludes that the Requirements of the existing standard are vague and ambiguous, and that, while Measures and Levels of Non-Compliance are defined, these are essentially unenforceable because of fundamental flaws within the requirements.

Assessment of PRC-001-0

General Comments

The SPCTF offers the following general comments:

1. None of the requirements within PRC-001-0 specifically indicate what protective systems are being addressed.
2. The phrase "protective relay or equipment" is a recurring phrase, and generally should be revised to "protective system" or "protective system equipment."
3. The phrase "If a protective relay or equipment failure reduces system reliability" is ambiguous, and needs additional clarification. This phrase does not clearly state when failures must be reported.
4. Many of the requirements list the Balancing Authority as an applicable entity. It does not seem that the Balancing Authority has the direct responsibility for any of these activities, and only needs to respond to the various issues when directed by the Transmission Operator and/or Generator Operator.

Applicability

4.1. Balancing Authorities
4.2. Transmission Operators
4.3. Generator Operators

The remainder of the PRC-series standards rarely assigns any responsibility for protection systems to any of the above entities. Specifically, the responsibilities for disturbance monitoring (which includes some monitoring of protective systems) and for protective system maintenance apply to the equipment owners, specifically Transmission Owners and Generator Owners. The current applicable entities do, however, have a role in the functions of this standard. The SPCTF asserts that Transmission Owner, Generator Owner, and Distribution Provider should be added to the list of Applicable Entities.

R1

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protective system schemes applied it its area.

This requirement is a statement of a highly laudable goal, but this is not specific and enforceable. In fact, the drafting team that was providing missing Measures and Compliance Elements was unable to assign either to this requirement.

It may be possible to restate this requirement in such a way to be measurable and enforceable. The protective system equipment owners (Transmission Owners, Generator Owners, and Distribution Providers) should be responsible to provide the necessary information to the Transmission Operator and Generator Operator to facilitate their familiarity with the relevant protective systems.

R2

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: ~~R2.1.~~If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. ~~R2.2.~~If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

Requirement R2 addresses the operating horizon, but the equipment owner entities will be familiar with the condition of their protective system equipment.

Therefore, the responsibility for this requirement must originate with the owner entities: the Transmission Owner, Generator Owner, and Distribution Provider. These entities should inform the Transmission Operator, Generator Operator, and Balancing Authorities of equipment failures pertinent to this requirement. The Transmission Operators may need to have to coordinate with each other, similar to the existing requirement R4.

The requirement for corrective action, “as soon as possible”, is vague and ambiguous, and needs modification to be specific.

As evidenced by the lack of a related Measure (via the drafting team for missing Measures and Compliance Elements), this requirement is currently not measurable.

R3

Not only new protective systems and changes to protective systems should be coordinated. A

> **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
>
> **R3.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
>
> **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

requirement should be added to require coordination of all existing protective systems. Then, requirement R3 should require the coordination new protective systems and changes to protective systems with existing protective systems.

Requirement R3 addresses the planning horizon; therefore, this responsibility should be assigned to the Transmission Owner, Generator Owner, and Distribution Provider.

In addition, R3.1 should be bi-directional; the Transmission entity should provide similar coordination with the Generator entity.

R4

> **R4.** Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

It's unclear whether this requirement addresses the operations planning horizon or the planning horizon.

If Requirement R4 addresses the planning horizon, the responsibilities should be assigned similarly to the recommendations for R3, to the Transmission Owner, Generator Owner, and Distribution Provider. If Requirement R4 addresses the planning horizon, it seems to be redundant with R3 to some extent.

R5

> **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:
>
> **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.
>
> **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.

Requirement R5 addresses the both the planning horizon and operating planning horizon. It is essential to the reliability of the system that this activity occurs, and it must occur in advance of any changes to the system.

In the operations planning horizon, the Operator entities should coordinate these changes with the Owner entities, since the Owners have the tools to analyze the effects of these system changes on the protective systems and the access to the protective systems to make any needed changes to the protective system.

In the planning horizon, the owner entities should be responsible for this requirement, similarly to Requirement R3.

R6

R6.	Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

Requirement R6 addresses the operating horizon. The Owners have to monitor the status of Special Protection Systems and provide the status to the Operators. The Operators then should coordinate the availability of Special Protection Systems between each other, and take any necessary operating actions to address issues with Special Protection Systems.

This requirement needs to better define "status of … Special Protection System…"

This requirement may be better moved to one of the PRC-series standards specifically addressing Special Protection Systems.

Related Standard
MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
Also, while reviewing PRC-001, the SPCTF noted that no existing NERC Standard requires that a consistent model be maintained for protection studies, such as that required by MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures, for other steady-state studies. Without such a model, various Transmission Owners, Generator Owners, and Distribution Providers cannot accurately apply the protective relaying. To address this deficiency, the SPCTF recommends that MOD-011, Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures, be modified to include the essential data for wide-area fault studies. The specific MOD-011 requirements are listed below, together with suggested modifications.

R1.2 – Generators
Recommend including direct-axis synchronous reactance (X_d), transient reactance (X_d'), sub transient reactance (X_d"), and the associated time constants (T_{do}, T_{do}', and T_{do}") for synchronous generators. For induction and inverter generators, generically include the data necessary to model the equipment in short circuit models in the positive, negative, and zero sequence domains.

R1.3 – Transmission Lines
Recommend specifying the positive and zero sequence impedance, including mutual impedances

R1.5 – Transformers
Recommend specifying positive sequence and zero sequence impedance, including all grounding effects.

FERC Assessment of PRC-001-0

In the October 20, 2006, the Notice of Proposed Rulemaking for adoption of NERC Standards (Docket Number RM06-16-000), the Federal Energy Regulatory Commission, for the most part, considered the operating horizon impacts of PRC-001. FERC proposed that PRC-001-0 be approved as mandatory and enforceable. They did, however, propose that NERC be directed to make modifications to PRC-001. The modifications proposed in the NOPR are excerpted from the NOPR and repeated below:

> "The Commission proposes to direct that NERC submit a modification to PRC-001-0 that: (1) includes Measures and Levels of Non-Compliance; (2) includes a requirement that relevant transmission operators and generator operators must be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities can carry out the appropriate corrective control actions consistent with those used in mitigating IROL violations; and (3) clarifies that, after being informed of failures in relays or protection system elements on the Bulk-Power System, transmission operators or generator operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes."

Other Activities related to PRC-001-0

The Standard Drafting Team on Missing Measures and Compliance Elements modified PRC-001-0 as a part of their work, but the requirements were not changed. As this report is being prepared, the modified Standard is being balloted.

A draft SAR for the revision of PRC-001-0 is included in the "Draft Reliability Standards Development Plan: 2007–2009", which was presented to the NERC Board of Trustees for their approval on November 1, 2006. This draft SAR is entitled, "System Protection Project (2009-01)", and discusses many of the same deficiencies in PRC-001-1 that were identified by the SPCTF.

Conclusion and Recommendation

As it exists today, enforcement of PRC-001-0 will be very difficult. The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the "operating horizon," "operations planning horizon," and "planning horizon" protection coordination issues, the deficiencies in the current standard are magnified.

The SPCTF recommends that the existing draft Standards Authorization Request that is included in the "Draft Reliability Standards Development Plan: 2007–2009" be modified to include the observations from the SPCTF assessment of PRC-001-0 and also include the modifications directed in the FERC NOPR on RM06-16-000. The SPCTF also recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards.

In addition, it is not possible to effectively coordinate protective systems without having accurate short circuit models of neighboring systems. To address these modeling issues related to data for short circuit calculations, the SPCTF recommends that a Standards Authorization Request be developed to modify Standard MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures, to address these issues. Data for short circuit calculations, as noted in this report, should be considered as additional requirements within MOD-013-1.

Appendices

Attachment A is not relevant to this SAR and was removed

Appendix B — SYSTEM PROTECTION AND CONTROL TASK FORCE

Charles W. Rogers
Chairman / RFC-ECAR Representative
Principal Engineer
Consumers Energy Co.

W. Mark Carpenter
Vice Chairman / ERCOT Representative
System Protection Manager
TXU Electric Delivery

John Mulhausen
FRCC Representative
Manager, Design and Standards
Florida Power & Light Co.

Joseph M. Burdis
ISO/RTO Representative
Senior Consultant / Engineer, Transmission and Interconnection Planning
PJM Interconnection, L.L.C.

William J. Miller
RFC-MAIN Representative
Consulting Engineer
Exelon Corporation

Deven Bhan
MRO Representative
Electrical Engineer, System Protection
Western Area Power Administration

Philip Tatro
NPCC Representative
Consulting Engineer
National Grid USA

Philip B. Winston
SERC Representative
Manager, Protection and Control
Georgia Power Company

Fred Ipock
SPP Representative
Senior Engineer - Substations & Protection
City Utilities of Springfield, Missouri

David Angell
WECC Representative
T&D Planning Engineering Leader
Idaho Power Company

John L. Ciufo
Canada Member-at-Large
Manager Reliability Standards (P&C/Telecom)
Hydro One, Inc.

Jim Ingleson
ISO/RTO Representative
Senior Electric System Planning Engineer
New York Independent System Operator

Evan T. Sage
Investor Owned Utility
Senior Engineer
Potomac Electric Power Company

James D. Roberts
Federal
Transmission Planning
Tennessee Valley Authority

Tom Wiedman
NERC Consultant
Wiedman Power System Consulting Ltd.

Henry (Hank) Miller
RFC-ECAR Alternate
Principal Electrical Engineer
American Electric Power

Baj Agrawal
WECC Alternate
Principal Engineer
Arizona Public Service Company

Michael J. McDonald
Senior Principal Engineer, System Protection
Ameren Services Company

Jonathan Sykes
Senior Principal Engineer, System Protection
Salt River Project

W. O. (Bill) Kennedy
Canada Member-at-Large
Principal
b7kennedy & Associates Inc.

Bob Stuart
NERC Blackout Investigation Team
Director of Business Development, Principal T&D Consultant
Elequant, Inc.

Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replace existing 'levels of non-compliance.') The violation severity levels must be applied for each requirement and may be combined to cover multiple requirements, as long as it is clear which requirements are included and that all requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: more than 95% but less than 100% compliant.
- **Moderate: mostly compliant with significant exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: more than 85% but less than or equal to 95% compliant.
- **High: marginal performance or results** — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: more than 70% but less than or equal to 85% compliant.
- **Severe: poor performance or results** — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: 70% or less compliant.

Compliance Monitor
Replace, ‘Regional Reliability Organization’ with ‘Regional Entity’

Fill-in-the-blank Requirements
Do not include any ‘fill-in-the-blank’ requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan. The effective date should be linked to the NERC BOT adoption date.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, ‘Associated Documents’.

Functional Model Version 3
Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Maureen E. Long
Standards Process Manager

June 11, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Comment Periods Open

The Standards Committee (SC) announces the following standards actions:

SAR for System Protection Coordination (Project 2007-06) Posted for 30-day Comment Period June 11–July 10, 2007

The SAR for Project 2007-06 — System Protection Coordination proposes to address the FERC directives in Order 693 and to address a number of technical shortcomings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

The purpose of the proposed standard is to assure that protection system application and performance issues are coordinated among all related entities. Please use this comment form to submit comments on this SAR.

SAR for Protection System Maintenance & Testing (Project 2007-17) Posted for 30-day Comment Period June 11–July 10, 2007

This SAR for Project 2007-17 — Protection System Maintenance and Testing proposes to merge the requirements from the following standards into a single standard to reduce the costs of compliance while also improving efficiencies:

- PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs
- PRC-011-0 — UVLS System Maintenance and Testing
- PRC-017-0 — Special Protection System Maintenance and Testing

The SAR also proposes to address the FERC directives in Order 693 and to address a number of technical shortcomings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

The purpose of the proposed standard is to ensure all transmission and generation protection systems affecting the reliability of the bulk power system are maintained and tested to support reliable operation performance when responding to abnormal system conditions. Please use this comment form to submit comments on this SAR.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Robert J. Rauschenbach	
Organization:	Ameren	
Telephone:	314-554-3535	
E-mail:	rrauschenbach@ameren.com	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR proposes to improve and expand upon the requirements in PRC-001 — System Protection Coordination. Note that some of the requirements in PRC-001 involve real-time control actions taken by entities other than the facility owners, and these requirements may be moved from PRC-001 into Project 2006-06 — Reliability Coordination.

The SAR proposes to address the FERC directives in Order 693 and to address a number of technical short comings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

Please review the SAR and then answer the questions on the following page. Please e-mail your comments on this form to sarcomm@nerc.net with the subject "Protection Maintenance SAR" by **July 10, 2007**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: None
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: No
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: Development of intercompany short circuit modeling should be cover in a separte MOD standard. Maintaining one large overall regional short circuit model is neither practical nor necessary. Standard methods to exchange short circuit data of tie-line plus one breakered bus into the neighboring systems should be adeqaute and be developed. Otherwise Ameren agrees with SPCTF recommendations.

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information

(Complete this page for comments from one organization or individual.)

Name:	Thad K. Ness
Organization:	American Electric Power (AEP)
Telephone:	614-716-2053
E-mail:	tkness@aep.com

NERC Region		Registered Ballot Body Segment
☒ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☒ RFC	☒	5 — Electric Generators
☐ SERC	☒	6 — Electricity Brokers, Aggregators, and Marketers
☒ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR proposes to improve and expand upon the requirements in PRC-001 — System Protection Coordination. Note that some of the requirements in PRC-001 involve real-time control actions taken by entities other than the facility owners, and these requirements may be moved from PRC-001 into Project 2006-06 — Reliability Coordination.

The SAR proposes to address the FERC directives in Order 693 and to address a number of technical short comings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

Please review the SAR and then answer the questions on the following page. Please e-mail your comments on this form to sarcomm@nerc.net with the subject "Protection Maintenance SAR" by **July 10, 2007**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☐ Yes

   ☒ No

   Comments: There might not be a directly reliability driver for improving this standard, but the standard should be improved to better clarify responsibilities.

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: None
   Comments: None

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: Possibly
   Comments: AEP and other utilities, with many years of experience serving customers and supporting the electric grid, have voluntarily integrated protection coordination processes into the core of their work practices . AEP fully supports improvements if they truly foster reliability and availability benefits to bulk power transfers. More Standards, Requirements, and Business Practices are not always better. If Standards create burdens on a utility's physical resources and budgets, then some mechanism must be available to allow for the needed changes.

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: For clarifying protective systems, the standard should not use the term Bulk Electric System, but should instead specify a voltage threshold for impacts to bulk system transfers - specifically; 'Facilites operated 200 kV and above and Regionally-defined, Operationally Significant facilities operated greater than 100 kv, but less than 199 kV'. The term 'affects' also needs to be clarified. Inclusion of all facilities greater than 100 kV does not benefit the reliability of national bulk power transfers. For example, the loss or misoperation of a 138 kV line serving a localized load center would not be detremental to bulk power transfers multiple busses away.

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: Jason Shaver		
Organization: American Transmission Co.		
Telephone: 262 506 6885		
E-mail: jshaver@atcllc.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
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☐ **SPP**	☐	7 — Large Electricity End Users
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR proposes to improve and expand upon the requirements in PRC-001 — System Protection Coordination. Note that some of the requirements in PRC-001 involve real-time control actions taken by entities other than the facility owners, and these requirements may be moved from PRC-001 into Project 2006-06 — Reliability Coordination.

The SAR proposes to address the FERC directives in Order 693 and to address a number of technical short comings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

Please review the SAR and then answer the questions on the following page. Please e-mail your comments on this form to sarcomm@nerc.net with the subject "Protection Maintenance SAR" by **July 10, 2007**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments: Standard has much room for improvement.

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments: Moving R6 regarding SPS monitoring and status notification to more appropriate PRC SPS section makes sense.

   Have concern about NERC SPCTF recommendation of merging system short-circuit databases for perfoming wide-area fault studies. See additional comments below.

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: Data entry and maintenance procedures for proposed wide-area short circuit model would need to be developed.
   Comments: Creating and maintaining the proposed wide-area short-circuit database, although useful, might prove quite difficult to implement.

   Among our concerns:

Impedance units- Ohms or per unit? If per unit, using what common base?

CAPE to ASPEN & ASPEN to CAPE conversion issues?

Need for unique and consistent bus numbers for all busses in combined database.

If using CAPE, coordination and application of database categories.

Who would be responsible for merging the databases and then maintaining the common database? How often would the databases be remerged to reflect system changes?

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: Background Information Section on this comment sheet should read:

   Please e-mail your comments on this form to sarcomm@nerc.net with subject "Protection Coordination SAR" in subject line, not "Protection Maintenance SAR" as stated.

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information	
(Complete this page for comments from one organization or individual.)	
Name:	Dean Bender
Organization:	Bonneville Power Administration
Telephone:	(360) 418-2040
E-mail:	dabender@bpa.gov

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR proposes to improve and expand upon the requirements in PRC-001 — System Protection Coordination. Note that some of the requirements in PRC-001 involve real-time control actions taken by entities other than the facility owners, and these requirements may be moved from PRC-001 into Project 2006-06 — Reliability Coordination.

The SAR proposes to address the FERC directives in Order 693 and to address a number of technical short comings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

Please review the SAR and then answer the questions on the following page. Please e-mail your comments on this form to sarcomm@nerc.net with the subject "Protection Maintenance SAR" by **July 10, 2007**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments: No known variance

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Nancy C. Denton	
Organization:	Consumers Energy Company	
Telephone:	517-788-1310	
E-mail:	ncdenton@cmsenergy.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR proposes to improve and expand upon the requirements in PRC-001 — System Protection Coordination. Note that some of the requirements in PRC-001 involve real-time control actions taken by entities other than the facility owners, and these requirements may be moved from PRC-001 into Project 2006-06 — Reliability Coordination.

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: N/A
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: N/A
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: None.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: Doug Hohlbaugh		
Organization: FirstEnergy		
Telephone: 330-384-4698		
E-mail: hohlbaughdg@firstenergycorp.com		
NERC Region		**Registered Ballot Body Segment**
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☒	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☒ RFC	☒	5 — Electric Generators
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☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: FirstEnergy

Lead Contact: Doug Hohlbaugh

Contact Organization:

Contact Segment:

Contact Telephone: 330-384-4698

Contact E-mail: hohlbaughdg@firstenergycorp.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Art Buanno	FE, Tranmission Planning & Protection	RFC	1
Bob McFeaters	FE, Tranmission Planning & Protection	RFC	1
Bill Duge	FE, Nuclear Generation	RFC	5
Ken Dresner	FE, Fossil Generation	RFC	5

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR proposes to improve and expand upon the requirements in PRC-001 — System Protection Coordination. Note that some of the requirements in PRC-001 involve real-time control actions taken by entities other than the facility owners, and these requirements may be moved from PRC-001 into Project 2006-06 — Reliability Coordination.

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☐ Yes

   ☒ No

   Comments: Under the section of Detailed Description it is stated:

   "This project will address the issues identified by the System Protection and Control Task Force for the planning-related requirements in PRC-001 as well as any planning-related concerns identified in FERC Order 693. (The operations-related requirements in PRC-001 are being addressed under Project 2006-06.) A detailed listing of the areas of the existing standard that need improvement is provided in Attachment B titled "NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination"

   It seems that it would be more effective to pull the PRC-001 standard from the scope of of the 2006-06 project which deals with mulitple standards and allow this SDT to focus on all aspects of the PRC-001. The SPCTF raised concerns with PRC-001 in both the planning and operations time-frame and it does not appear that the 2006-06 project is scoped to address the SPCTF items.

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☐ Yes

   ☒ No

   Comments: FE agrees with the SPCTF that the TO, GO and DP should be added to the applicability section of this standard as many of the requirements will originate from these entities. However, it may be necessary to to add the Tranmission Planner (TP) entity for "planning" related requirements. For example, the existing R3 requires coordination of new or revised protections systems. It may be short-sighted to assume that the TO is the entity who would coordinate this work; there may be situations where a Transmission Planner performs this work and is best suited to share the information with neighboring system owners/planners as well as the Planning Coordinator.

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments: Aware of none

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments: Aware of none

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: none

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: FRCC

Lead Contact: Eric Senkowicz

Contact Organization: FRCC

Contact Segment: 10

Contact Telephone: 813-207-7980

Contact E-mail: esenkowicz@frcc.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Alan Gale	City of Tallahassee	FRCC	5

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR proposes to improve and expand upon the requirements in PRC-001 — System Protection Coordination. Note that some of the requirements in PRC-001 involve real-time control actions taken by entities other than the facility owners, and these requirements may be moved from PRC-001 into Project 2006-06 — Reliability Coordination.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☒ No

   Comments: Incorporating assessments by subject matter experts such as this NERC SPCTF / Planning Committee assessment into the NERC Standards revision SAR project is an efficient way to supplement project SARs and allows for valuable input at the front-end of the standards process.

   Attachments A and C are not included in the SAR and Attachment B is identified as "Supporting Material". It may be clearer to include all applicable documents within the SAR including including relevant excerpts from any FERC assessmentss and requested changes to the standard.

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☐ Yes

   ☐ No

   Comments: This question may be better addressed as the standard is drafted.

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: The Drafting team should coordinate any system protection terminology introduced or re-defined within this standard with other system protection related SARs (i.e. Distrurbance monitoring, System Protection Maintenance and Testing) to ensure common terminology is appropriately defined in the standards glossary.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)	
Name:	Roger Champagne
Organization:	Hydro-Québec TransÉnergie
Telephone:	514 289-2211, X 2766
E-mail:	champagne.roger.2@hydro.qc.ca

NERC Region		Registered Ballot Body Segment
☐ ERCOT	☒	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☐ Yes

   ☒ No

   Comments: recommend that Transmission Planners be added

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments: No Regional Variance

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments: No Business Practice

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: none

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Ron Falsetti	
Organization:	IESO	
Telephone:	905-855-6187	
E-mail:	ron.falsetti@ieso.ca	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
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Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☒ No

   Comments: It is not clear based on the information presented how all the functional entities are involved. As an example, no reference is noted in the documents for PC responsibility. Is it inferred that if a coordination model is developed on a wide area basis, the PC will be the responsible entity?

   Functional Model entity definitions, tasks, and obligations must be followed while developing applicability of the requirements.

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

Comments:
The IESO commends NERC, the SDT and the SPCTF (White Paper) for providing clarifications and improvements in the system protection areas.

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<table>
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(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
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<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
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☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
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<tr><td colspan="3"></td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name: IRC Standards Review Committee

Lead Contact: Charles Yeung

Contact Organization: SPP

Contact Segment: 2

Contact Telephone: 832-724-6142

Contact E-mail: cyeung@spp.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Jim Castle	NYISO	NPCC	2
Alicia Daugherty	PJM	RFC	2
Ron Falsetti	IESO	NPCC	2
Matt Goldberg	ISO-NE	NPCC	2
Brent Kingsford	CAISO	WECC	2
Anita Lee	AESO	WECC	2
Steve Myers	ERCOT	ERCOT	2
William Phillips	MISO	RFC+MRO+SERC	2

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1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☒ No

   Comments: It is not clear based on the information presented if all the functional entities involved are identified in the scope of the standard. As an example, no reference is noted in the documents for TP responsibility. It is inferred that if a coordination model is developed on a wide area basis, the PC will be the only responsible entity. However there may be requirements for the TP as well.

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   Regional Variance:
   Comments:

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   Business Practice:
   Comments:

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   Comments:

1. The SRC commends NERC, the SDT and the SPCTF for providing this clarification and improvements in the system protection areas.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Walter Marusenko	
Organization:	Manitoba Hydro	
Telephone:	204-487-5407	
E-mail:	wmarusenko@hydro.mb.ca	
NERC Region		**Registered Ballot Body Segment**
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments: No comments.

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments: No comments.

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments: No comments

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: None.
   Comments: No variance necessary.

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: None.
   Comments: No comments.

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: No comments.

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Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:	Midwest Reliability Organization (MRO)
Lead Contact:	Joe Knight
Contact Organization:	**MRO for Group (GRE - for lead contact)**
Contact Segment:	10
Contact Telephone:	763.241.5633
Contact E-mail:	jknight@grenergy.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Neal Balu	WPS	MRO	10
Terry Bilke	MISO	MRO	10
Robert Coish, Chair	MHEB	MRO	10
Carol Gerou	MP	MRO	10
Ken Goldsmith	ALT	MRO	10
Jim Haigh	WAPA	**MRO**	10
Tom Mielnik	MEC	MRO	10
Pam Oreschnick	XEL	MRO	10
Dave Rudolph	BEPC	MRO	10
Eric Ruskamp	LES	MRO	10
MIke Brytowski, Secretary	MRO	MRO	10
28 Additional MRO Members	Not Named Above	MRO	10

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR proposes to improve and expand upon the requirements in PRC-001 — System Protection Coordination. Note that some of the requirements in PRC-001 involve real-time control actions taken by entities other than the facility owners, and these requirements may be moved from PRC-001 into Project 2006-06 — Reliability Coordination.

The SAR proposes to address the FERC directives in Order 693 and to address a number of technical short comings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

Please review the SAR and then answer the questions on the following page. Please e-mail your comments on this form to sarcomm@nerc.net with the subject "Protection Maintenance SAR" by **July 10, 2007**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: None
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: None
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments:
   1. The MRO commends NERC and the SDT for taking the necessary steps to remove the vagueness and ambiguity in the requirements; as well as the need to have clarity and measurability now that the industry has transitioned to mandatory and enforceable standards.

2. The SPCTF Assessment of PRC-001-1 did not mention how they would address "Corrective Actions" listed in R2. The MRO requests that the SDT expand on what the scope of these "Corrective Actions" is meant to be (e.g. real-time, or after the fact repair or replacement of defective equipment).

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Public Service Commission of South Carolina

Lead Contact: Phil Riley

Contact Organization: Public Service Commission of South Carolina

Contact Segment: 9

Contact Telephone: 803-896-5154

Contact E-mail: philip.riley@psc.sc.gov

Additional Member Name	Additional Member Organization	Region*	Segment*
Mignon L. Clyburn	Public Service Commission of SC	SERC	9
Elizabeth B. "Lib" Fleming	Public Service Commission of SC	SERC	9
G. O'Neal Hamilton	Public Service Commission of SC	SERC	9
John E. "Butch" Howard	Public Service Commission of SC	SERC	9
Randy Mitchell	Public Service Commission of SC	SERC	9
C. Robert "Bob" Moseley	Public Service Commission of SC	SERC	9
David A. Wright	Public Service Commission of SC	SERC	9

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments: N/A

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments: N/A

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: N/A

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: Mike Gentry		
Organization: Salt River Project		
Telephone: 602-236-6408		
E-mail: Mike.Gentry@srpnet.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This SAR proposes to improve and expand upon the requirements in PRC-001 — System Protection Coordination. Note that some of the requirements in PRC-001 involve real-time control actions taken by entities other than the facility owners, and these requirements may be moved from PRC-001 into Project 2006-06 — Reliability Coordination.

The SAR proposes to address the FERC directives in Order 693 and to address a number of technical short comings identified by stakeholders and the System Protection and Control Task Force and to bring the standard into conformance with the "Standard Review Guidelines."

Please review the SAR and then answer the questions on the following page. Please e-mail your comments on this form to sarcomm@nerc.net with the subject "Protection Maintenance SAR" by **July 10, 2007**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments:

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance:
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice:
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: I am concerned with the language proposed by FERC and the comparison to reactions to IROL's. Will FERC's requirement apply to a single protection system that has a redundant protection system? Will FERC's requirement apply to a system that is in an "overexposed" state? Will FERC's requirement apply to a system that may be exposed to slow 30 cycle of less tripping. These conditions must be identified in detail as to what will need to meet the "returning the system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes." FERC requirement

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: SERC EC Protection & Control Subcommittee (PCS)

Lead Contact: Jay Farrington

Contact Organization: Alabama Electric Cooperative, Inc.

Contact Segment: 1

Contact Telephone: (334) 427-3225

Contact E-mail: jay.farrington@powersouth.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Robert Rauschenbach	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
Jammie Lee	Entergy	SERC	1
Tom Seeley	E.ON-U.S.	SERC	1
Steve Waldrep	Georgia Power Company	SERC	1
Hong-Ming Shuh	Georgia Transmission Corporation	SERC	1
Neal Jones	Georgia Transmission Corporation	SERC	1
Jerry Blackley	Progress Energy Carolinas	SERC	1
Pat Huntley	SERC Reliability Corp.	SERC	10
Marion Frick	South Carolina Electric & Gas Co.	SERC	1
Bridget Coffman	South Carolina Public Service Authority	SERC	1
George Pitts	Tennessee Valley Authority	SERC	1
Meyer Kao	Tennessee Valley Authority	SERC	1
Phil Winston	Georgia Power Company	SERC	1
Ernesto Paon	Municipal Electric Authority of Georgia	SERC	1

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the proposed scope of this SAR?

   ☐ Yes

   ☒ No

   Comments: Consideration should be given to splitting this effort among 2 or 3 standards to address the operating, operations planning, and planning horizons. Consideration should also be given to moving the operating training requirements to another standard (if not already covered by an existing standard).

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments: The requirements for the PC, TO, GO, and DP (planning horizon) should be in a separate standard than those for the RC, BA, TOP, and GOP (operating and operations planning horizons).

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: none
   Comments:

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: none
   Comments:

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

Comments: none

Please use this form to submit comments on the proposed SAR for Project 2007-06 — System Protection Coordination. Comments must be submitted by **July 10, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "System Protection" in the subject line. If you have questions please contact Al Calafiore at al.calafiore@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Southwest Transmission Cooperative, Inc.

Lead Contact: E. William Riley

Contact Organization: Southwest Transmission Cooperative, Inc.

Contact Segment: **1**

Contact Telephone: 520-586-5440

Contact E-mail: briley@swtransco.coop

Additional Member Name	Additional Member Organization	Region*	Segment*
Tom D. Spence, P.E	Southwest Transmission Coop., Inc.	**WECC**	1

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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Please review the SAR and then answer the questions on the following page. Please e-mail your comments on this form to sarcomm@nerc.net with the subject "Protection Maintenance SAR" by **July 10, 2007**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to improve the requirements in this standard?

   ☒ Yes

   ☐ No

   Comments: We agree that there is a need to improve the requirements of Standard PRC-001-0 and Standard MOD-011-0 as described in the supplemental document "NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination". It is important to modify ambiguous statements such as "…corrective action needs to be taken…" and "must be done…as soon as possible…". By making the improvements described in the SAR, the standard will provide the applicable entities with more definitive requirements that will allow entities to provide specific responsibilities to internal work groups within the standard utility organization.

2. Do you agree with the proposed scope of this SAR?

   ☒ Yes

   ☐ No

   Comments: Another important change described in this SAR is the requirement to have an up-to-date accurate model of the transmission system for protection studies. It is extremely important to develop these accurate models to allow enhance the reliability of the bulk-electric system. There are efforts underway in the southwest that apply directly to the development of this type of model by late 2007.

3. Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?

   ☒ Yes

   ☐ No

   Comments: We agree that the applicable entities for this standard be modified to include the various "Owner" entities as described in the NERC Functional Model Version 3.

4. If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.

   Regional Variance: N/A
   Comments: Not aware of any Regional Variance requirements

5. If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.

   Business Practice: N/A
   Comments: Not aware of any Business Practice needs

6. If you have any other comments on this SAR that you haven't provided above, please provide them here.

   Comments: N/A

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on 1st Draft of System Protection Coordination SAR (Project 2007-06)

The System Protection Coordination SAR requesters thank all commenters who submitted comments on the first draft of SAR. This SAR was posted for a 30-day public comment period from June 11 through July 10, 2007. The requesters asked stakeholders to provide feedback on the standard through a special SAR Comment Form. There were 17 sets of comments, including comments from 72 different people from more than 48 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The SAR drafting team made two changes to the SAR based on stakeholder comment:

- Added the Transmission Planner as a reliability function that may be assigned requirements in the revised standard
- Added a sentence to clarify that the monitoring requirements in PRC-001 will not be included in the scope of revisions addressed under this project as they are already being addressed under Project 2006-06 — Reliability Coordination.

Based on the comments received, the drafting team is recommending that the Standards Committee authorize moving the SAR forward to the standard drafting stage of the standards development process.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/System_Protection_Project_2007-06.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Anita Lee (G6)	AESO		✓								
2.	Jay Farrington (G2)	Alabama Electric Coop., Inc.				✓	✓	✓				
3.	Ken Goldsmith (G4)	ALT										✓
4.	Robert Rauschenbach (G2)(I)	Ameren			✓			✓				
5.	Thad Kness	American Electric Power (AEP)	✓				✓	✓				
6.	Jason Shaver	American Transmission Co.	✓									
7.	Dave Rudolph (G4)	BEPC										✓
8.	Dean Bender	Bonneville Power Administration (BPA)	✓		✓		✓	✓				
9.	Brent Kingsford (G6)	CAISO		✓								
10.	Alan Gale (G5)	City of Tallahassee	✓		✓		✓	✓				
11.	Glen McCartney (G3)	Constellation Energy			✓		✓	✓				
12.	Michael Gildea (G3)	Constellation Energy			✓		✓	✓				
13.	Nancy C. Denton	Consumers Energy Company			✓	✓						
14.	Tom Seeley (G2)	E. ON-U.S.	✓									
15.	Charlie Fink (G2)	Entergy	✓		✓		✓	✓				
16.	Jammie Lee (G2)	Entergy	✓		✓		✓	✓				
17.	Steve Myers (G6)	ERCOT										✓
18.	Ken Dresner (G7)	FE, Fossil Generation	✓		✓		✓	✓				
19.	Bill Duge (G7)	FE, Nuclear Generation	✓		✓		✓	✓				
20.	Art Buanno (G7)	FE, Tranmission Planning & Protection	✓		✓		✓	✓				
21.	Bob McFeaters (G7)	FE, Tranmission Planning & Protection	✓		✓		✓	✓				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
22.	Doug Hohlbaugh (G7)	FirstEnergy	✓		✓		✓	✓				
23.	Eric Senkowicz	FRCC										✓
24.	Phil Winston (G2)	Georgia Power Company			✓							
25.	Steve Waldrep (G2)	Georgia Power Company			✓							
26.	Hong-Ming Shuh (G2)	Georgia Transmission Corp.	✓		✓							
27.	Neal Jones (G2)	Georgia Transmission Corp.	✓		✓							
28.	David Kiguel (G3)	Hydro One Networks	✓		✓							
29.	Roger Champagne (G3)(I)	HydroQuebec TransEnergie (HQTE)	✓									
30.	Matt Goldberg (G6)	IESO		✓								
31.	Ron Falsetti (G3) (G6) (I)	IESO		✓								
32.	Charles Yeung (G6)	SPP		✓								
33.	Kathleen Goodman (G3)	ISO-New England		✓								
34.	William Shemley (G3)	ISO-New England		✓								
35.	Eric Ruskamp (G4)	LES	✓		✓		✓	✓				
36.	Donald Nelson (G3)	MADPC									✓	
37.	Robert Coish (G4)	Manitoba Hydro EB	✓		✓		✓	✓				
38.	Walter Marusenko	Manitoba Hydro EB	✓		✓		✓	✓				
39.	Tom Mielnik (G4)	MEC										✓
40.	Joe Knight (G4)	Midwest Reliability Organization										✓
41.	Mike Brytowski (G4)	Midwest Reliability Organization										✓
42.	Terry Bilke (G4)	MISO		✓								
43.	William Phillips (G6)	MISO		✓								
44.	Carol Gerou (G4)	MP	✓		✓		✓	✓				
45.	Ernesto Paon (G2)	Municipal Electric Authority of GA	✓		✓		✓					
46.	Michael Shiavone (G3)	National Grid US	✓									
47.	Greg Campoli (G3)	New York ISO		✓								
48.	Jim Castle (G6)	New York ISO		✓								
49.	Ralph Rufrano (G3)	New York Power Authority	✓		✓							
50.	Guy V. Zito (G3)	NPCC										✓
51.	Al Adamson (G3)	NY State Reliability										✓

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
		Council										
52.	Alicia Daugherty (G6)	PJM		✓								
53.	Jerry Blackley (G2)	Progress Energy Carolinas	✓		✓		✓	✓				
54.	C. Robert Moseley (G1)	PSC of South Carolina									✓	
55.	David A. Wright (G1)	PSC of South Carolina									✓	
56.	Elizabeth B. Fleming (G1)	PSC of South Carolina									✓	
57.	G. O'Neal Hamilton (G1)	PSC of South Carolina									✓	
58.	John E. Howard (G1)	PSC of South Carolina									✓	
59.	Mignon L. Clyburn (G1)	PSC of South Carolina									✓	
60.	Phil Riley (G1)	PSC of South Carolina									✓	
61.	Randy Mitchell (G1)	PSC of South Carolina									✓	
62.	Mike Gentry	Salt River Project	✓		✓		✓	✓				
63.	Bridget Coffman (G2)	SC Public Service Authority	✓									
64.	Pat Huntley (G2)	SERC Reliability Corp.										✓
65.	Marion Frick (G2)	South Carolina Electric & Gas Co.			✓		✓	✓				
66.	E. William Riley	Southwest Transmission Coop.	✓									
67.	Tom D. Spence	Southwest Transmission Coop.	✓									
68.	George Pitts (G2)	Tennessee Valley Authority	✓		✓		✓					
69.	Meyer Kao (G2)	Tennessee Valley Authority	✓		✓		✓					
70.	Jim Haigh (G4)	WAPA	✓					✓				
71.	Neal Balu (G4)	WPS			✓		✓	✓				
72.	Pam Oreschnick (G4)	XEL	✓		✓		✓	✓				

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – Public Service Commission of South Carolina (PSC SC)
G2 – SERC EC Protection & Control Subcommittee (SERC EC PCS)
G3 – CP9 Reliability Standards Working Group (CP9 RSWG)
G4 – Midwest Reliability Organization (MRO)
G5 – FRCC
G6 – IRC Standards Review Committee
G7 – FirstEnergy

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1. **Do you agree that there is a reliability-related need to improve the requirements in this standard?**

Summary Consideration: Most commenters agreed that there is a reliability-related need for this SAR. There were no changes made in response to these comments.

Question #1			
Commenter	**Yes**	**No**	**Comment**
AEP		☑	There might not be a directly reliability driver for improving this standard, but the standard should be improved to better clarify responsibilities.
Response: The SAR DT agrees with the comment that the standard should be improved to better clarify responsibilities, but the drafting team also believes that clarifying responsibilities is reliability related.			
SWTC	☑		We agree that there is a need to improve the requirements of Standard PRC-001-0 and Standard MOD-011-0 as described in the supplemental document "NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination". It is important to modify ambiguous statements such as "...corrective action needs to be taken..." and "must be done...as soon as possible...". By making the improvements described in the SAR, the standard will provide the applicable entities with more definitive requirements that will allow entities to provide specific responsibilities to internal work groups within the standard utility organization.
Response: The SAR DT thanks you for your support.			
ATC	☑		Standard has much room for improvement.
Response: The SAR DT agrees with the comment.			
PSC SC	☑		
SERC EC PCS	☑		
BPA	☑		
Consumers Energy	☑		
IESO	☑		
SRP	☑		
Manitoba Hydro	☑		
CP9 RSWG	☑		
Ameren	☑		
MRO	☑		

Question #1			
Commenter	**Yes**	**No**	**Comment**
HQTE	☑		
FRCC	☑		
IRC SRC	☑		
FirstEnergy	☑		

2. **Do you agree with the proposed scope of this SAR?**

Summary Consideration: Most commenters agreed with the proposed scope of the SAR. The SAR DT modified the SAR to clarify that it will coordinate with other DTs to ensure that all requirements in PRC-001will be addressed by one and only one drafting team. The monitoring requirements will be transferred to the DT working on Project 2006-06 for Reliability Coordination.

Question #2			
Commenter	**Yes**	**No**	**Comment**
SERC EC PCS		☑	Consideration should be given to splitting this effort among 2 or 3 standards to address the operating, operations planning, and planning horizons. Consideration should also be given to moving the operating training requirements to another standard (if not already covered by an existing standard).
Response: The SDT will coordinate with the Reliability Coordination standard drafting team working on Project 2006-06 to address these issues. The SAR DT believes that the monitoring requirements should be addressed by the Reliability Coordination SDT, however for coordination and understanding, the SAR DT believes the remaining requirements should be in one standard.			
FirstEnergy		☑	Under the section of Detailed Description it is stated: "This project will address the issues identified by the System Protection and Control Task Force for the planning-related requirements in PRC-001 as well as any planning-related concerns identified in FERC Order 693. (The operations-related requirements in PRC-001 are being addressed under Project 2006-06.) A detailed listing of the areas of the existing standard that need improvement is provided in Attachment B titled "NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination" It seems that it would be more effective to pull the PRC-001 standard from the scope of of the 2006-06 project which deals with mulitple standards and allow this SDT to focus on all aspects of the PRC-001. The SPCTF raised concerns with PRC-001 in both the planning and operations time-frame and it does not appear that the 2006-06 project is scoped to address the SPCTF items.
Response: The SAR DT modified the SAR to clarify that it will coordinate with other drafting teams to ensure that all requirements in PRC-001 will be addressed by one and only one drafting team. The monitoring requirements will be transferred to the DT working on project 2006-06 Reliability Coordination)			
FRCC	☑	☑	Incorporating assessments by subject matter experts such as this NERC SPCTF / Planning Committee assessment into the NERC Standards revision SAR project is an efficient way to supplement project SARs and allows for valuable input at the front-end of the standards process.

			Attachments A and C are not included in the SAR and Attachment B is identified as "Supporting Material". It may be clearer to include all applicable documents within the SAR including relevant excerpts from any FERC assessments and requested changes to the standard.
Response: The SAR DT will ensure that all attachments are clearly labeled and all pertinent documents are included in the final posting.			
SWTC	☑		Another important change described in this SAR is the requirement to have an up-to-date accurate model of the transmission system for protection studies. It is extremely important to develop these accurate models to allow enhance the reliability of the bulk-electric system. There are efforts underway in the southwest that apply directly to the development of this type of model by late 2007.
Response: The SAR DT agrees with your observation- please note the SPCTF's proposed changes for modeling are not addressed in this SAR – they are expected to be addressed in a separate SAR to revise MOD-011.			
ATC	☑		Moving R6 regarding SPS monitoring and status notification to more appropriate PRC SPS section makes sense. Have concern about NERC SPCTF recommendation of merging system short-circuit databases for perfoming wide-area fault studies. See additional comments below.
Response: The SAR DT agrees that R6 should be addressed in another standard; however, the SAR DT believes it belongs in a standard that addresses a broader range of monitoring activities. Please see the summary consideration of comments			
PSC SC	☑		
AEP	☑		
BPA	☑		
Consumers Energy	☑		
IESO	☑		
SRP	☑		
Manitoba Hydro	☑		
CP9 RSWG	☑		
Ameren	☑		
MRO	☑		
HQTE	☑		

IRC SRC	☑		

3. **Do you agree with the applicability of the proposed SAR (Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Operators, Transmission Owners, Generator Owners, Generator Operators and Distribution Providers)?**

Summary Consideration: Based on stakeholder comments, Transmission Planners have been added to the list of applicable entities.

Question #3			
Commenter	**Yes**	**No**	**Comment**
FRCC			This question may be better addressed as the standard is drafted.
Response: The SAR DT is required to identify the proposed applicability. The applicability will be finalized during standard drafting			
CP9 RSWG		☑	recommend that Transmission Planners be added
Response: The SAR DT agrees and Transmission Planners have been added to the applicability list.			
HQTE		☑	recommend that Transmission Planners be added
Response: The SAR DT agrees and Transmission Planners have been added to the applicability list.			
FirstEnergy		☑	FE agrees with the SPCTF that the TO, GO and DP should be added to the applicability section of this standard as many of the requirements will originate from these entities. However, it may be necessary to add the Transmission Planner (TP) entity for "planning" related requirements. For example, the existing R3 requires coordination of new or revised protections systems. It may be short-sighted to assume that the TO is the entity who would coordinate this work; there may be situations where a Transmission Planner performs this work and is best suited to share the information with neighboring system owners/planners as well as the Planning Coordinator.
Response: The SAR DT agrees and Transmission Planners have been added to the applicability list.			
IESO	☑	☑	It is not clear based on the information presented how all the functional entities are involved. As an example, no reference is noted in the documents for PC responsibility. Is it inferred that if a coordination model is developed on a wide area basis, the PC will be the responsible entity? Functional Model entity definitions, tasks, and obligations must be followed while developing applicability of the requirements.
Response: the SAR DT checked all the functional entities that are currently assigned responsibility for requirements in PRC-001 and also checked those functional entities that are expected to be assigned requirements based on the SPTCF analysis of PRC-001. Please see the SPTCF report posted as a supporting document on the website.			

Please note the SPCTF's proposed changes for modeling are not addressed in this SAR – they are expected to be addressed in another SAR for modifications to MOD-011. As envisioned, a new requirement may need to be developed to support the orignial R1 which says: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. Although the original R1 is not written in a format that is easy to measure, the SAR DT believes the intent of R1 is to ensure that real-time operating personnel have information about protection schemes so they will know what actions to take when the protection schemes are not in service. The SAR DT believes the Planning Coordinator may be the best functional entity to provide this data to the real-time operating personnel. As envisioned, this discussion will take place with stakeholders during standard drafting. The standards process requires that DTs consider the Functional Model elements when developing standards.			
IRC SRC	☑	☑	It is not clear based on the information presented if all the functional entities involved are identified in the scope of the standard. As an example, no reference is noted in the documents for TP responsibility. It is inferred that if a coordination model is developed on a wide area basis, the PC will be the only responsible entity. However there may be requirements for the TP as well.
Response: The SAR DT agrees and Transmission Planners have been added to the applicability list.			
SERC EC PCS	☑		The requirements for the PC, TO, GO, and DP (planning horizon) should be in a separate standard than those for the RC, BA, TOP, and GOP (operating and operations planning horizons).
Response: While the SAR DT agrees that some requirements for entities providing real time operations should be transferred to other standards, for coordination and understanding the SAR DT believes the remaining requirements should be in one standard.			
SWTC	☑		We agree that the applicable entities for this standard be modified to include the various "Owner" entities as described in the NERC Functional Model Version 3.
Response: The SAR DT agrees - thank you for your comments.			
PSC SC	☑		
AEP	☑		
BPA	☑		
Consumers Energy	☑		
SRP	☑		
ATC	☑		

Manitoba Hydro	☑		
Ameren	☑		
MRO	☑		

4. **If you know of a Regional Variance that should be developed as part of this SAR, please identify that for us. If not, please explain in the comment area.**

Summary Consideration: The stakeholders who submitted comments did not identify any regional variances.

Question #4		
Commenter	**Regional Variance**	**Comment**
PSC SC	N/A	
SERC EC PCS	None.	
AEP	None.	None.
BPA		No known variance.
Consumers Energy	N/A	
SWTC	N/A	Not aware of any Regional Variance requirements.
ATC	N/A	
Manitoba Hydro	None	No variance necessary.
CP9 RSWG	N/A	No Regional Variance
Ameren	None	
MRO	None	
HQTE		No Regional Variance
FRCC	N/A	
FirstEnergy		Aware of none

5. **If you are aware of a Business Practice that needs to be developed to support the proposed SAR, please identify that for us.**

Summary Consideration: The stakeholders who submitted comments did not identify any specific business practice that need to be developed to support the modifications to PRC-001 proposed with this SAR.

Question #5		
Commenter	**Business Practice**	**Comment**
AEP	Possibly	AEP and other utilities, with many years of experience serving customers and supporting the electric grid, have voluntarily integrated protection coordination processes into the core of their work practices . AEP fully supports improvements if they truly foster reliability and availability benefits to bulk power transfers. More Standards, Requirements, and Business Practices are not always better. If Standards create burdens on a utility's physical resources and budgets, then some mechanism must be available to allow for the needed changes.
Response: Please monitor the work of the SDT and advise us if added burdens are created and advise us of the need for any business practice or other mechanism necessary.		
ATC	Data entry and maintenance procedures for proposed wide-area short circuit model would need to be developed.	Creating and maintaining the proposed wide-area short-circuit database, although useful, might prove quite difficult to implement. Among our concerns: Impedance units- Ohms or per unit? If per unit, using what common base? CAPE to ASPEN & ASPEN to CAPE conversion issues? Need for unique and consistent bus numbers for all busses in combined database. If using CAPE, coordination and application of database categories. Who would be responsible for merging the databases and then maintaining the common database? How often would the databases be remerged to reflect system changes?
Response: Please note the SPCTF's proposed changes for modeling are not addressed in this SAR – they are expected to be addressed in a SAR proposing changes to MOD-011.		
PSC SC		N/A
SERC EC PCS	None.	
Consumers Energy	N/A	
SWTC	N/A	Not aware of any Business Practice needs.
Manitoba Hydro	None	No comments
CP9 RSWG		No Business Practice

Question #5		
Commenter	**Business Practice**	**Comment**
Ameren	No	
MRO	None	
HQTE		No Business Practice
FirstEnergy		Aware of none

6. **If you have any other comments on this SAR that you haven't provided above, please provide them here.**

Summary Consideration: The SAR DT did not make any changes to the SAR based on modifications proposed by stakeholders in response to this question.

Question #6	
Commenter	**Comment**
AEP	For clarifying protective systems, the standard should not use the term Bulk Electric System, but should instead specify a voltage threshold for impacts to bulk system transfers - specifically; 'Facilites operated 200 kV and above and Regionally-defined, Operationally Significant facilities operated greater than 100 kv, but less than 199 kV'. The term 'affects' also needs to be clarified. Inclusion of all facilities greater than 100 kV does not benefit the reliability of national bulk power transfers. For example, the loss or misoperation of a 138 kV line serving a localized load center would not be detremental to bulk power transfers multiple busses away.
Response: The comment will be referred to the SDT when convened for consideration when drafting the standard.	
FRCC	The Drafting team should coordinate any system protection terminology introduced or re-defined within this standard with other system protection related SARs (i.e. Disturbance monitoring, System Protection Maintenance and Testing) to ensure common terminology is appropriately defined in the standards glossary.
Response: This coordination is required by the standards process. The comment will be referred to the SDT when convened for consideration when drafting the standard.	
SRP	I am concerned with the language proposed by FERC and the comparison to reactions to IROL's. Will FERC's requirement apply to a single protection system that has a redundant protection system? Will FERC's requirement apply to a system that is in an "overexposed" state? Will FERC's requirement apply to a system that may be exposed to slow 30 cycle of less tripping. These conditions must be identified in detail as to what will need to meet the "returning the system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes." FERC requirement
Response: The comment will be referred to the SDT when convened for consideration when drafting the standard.	
ATC	Background Information Section on this comment sheet should read: Please e-mail your comments on this form to sarcomm@nerc.net with subject "Protection Coordination SAR" in subject line, not "Protection Maintenance SAR" as stated.
Response: Thank you for your comment	
Ameren	Development of inter-company short circuit modeling should be cover in a separate MOD standard. Maintaining one large overall regional short circuit model is neither practical nor necessary. Standard methods to exchange short circuit data of tie-line plus one breakered bus into the neighboring systems should be adequate and be developed. Otherwise Ameren agrees with SPCTF recommendations.
Response: Please note the SPCTF's proposed changes for modeling are not addressed in this SAR – they are expected to be addressed in a SAR proposing changes to MOD-011.	
MRO	The MRO commends NERC and the SDT for taking the necessary steps to remove the vagueness and ambiguity

	in the requirements; as well as the need to have clarity and measurability now that the industry has transitioned to mandatory and enforceable standards. The SPCTF Assessment of PRC-001-1 did not mention how they would address "Corrective Actions" listed in R2. The MRO requests that the SDT expand on what the scope of these "Corrective Actions" is meant to be (e.g. real-time, or after the fact repair or replacement of defective equipment).
Response: These issues are discussed in FERC Order 693 and will be considered by the SDT	
IESO	The IESO commends NERC, the SDT and the SPCTF (White Paper) for providing clarifications and improvements in the system protection areas.
Response: Thank you	
IRC SRC	The SRC commends NERC, the SDT and the SPCTF for providing this clarification and improvements in the system protection areas.
Response: Thank you	
PSC SC	N/A
SERC EC PCS	None.
Consumers Energy	None.
SWTC	N/A
Manitoba Hydro	No comments
CP9 RSWG	None
HQTE	None
FirstEnergy	none

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard	**PRC-001-1 — System Protection Coordination (Project 2007-06)**
Request Date	May 7, 2007
Revised Date	July 27, 2007

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)
Name NERC System Protection and Control Task Force (Attachment A)	☐	New Standard
Primary Contact Charles Rogers (SPCTF Chairman)	☒	Revision to existing Standard
Telephone 517-788-0027 Fax 517-788-0917	☐	Withdrawal of existing Standard
E-mail cwrogers@cmsenergy.com	☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

The purpose of standard PRC-001-1 — System Protection Coordination should remain "To ensure system protection is coordinated among operating entities." The standard should be revised to:

1. Assure that Protection System application and performance issues are coordinated among all related entities.
2. Correct the applicable entities within the standard to reflect the actual functional responsibilities, as described in the NERC Functional Model.
3. Incorporate other general improvements described in the standards development work plan and from other sources.
4. Address directives received from ERO regulatory authorities.
5. Consider the observations and recommendations developed by the NERC SPCTF, which are detailed in the attached report (Attachment B), approved by the Planning Committee in December 2006.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

Protection system coordination is an absolute necessity for the North American electric system to operate properly. PRC-001 is a Version 0 standard, and was translated from an operating policy that was appropriate in an era of voluntary compliance.

The Version 0 standards and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update those standards, incorporating improvements to make the standards more suitable for enforcement.

Both FERC (within Order 693) and the SPCTF (in their report on PRC-001) identified significant shortcomings in the existing standard.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

The existing PRC-001 Standard has been identified in the Reliability Standards Development Plan as requiring revision, within the FERC Order 693 as requiring revisions, and by a SPCTF report (attached) which identified a number of issues with the existing standard (the SPCTF report, which precedes FERC Order 693, also includes observations from the preceding FERC NOPR on RM-06-16-000). This revision of PRC-001 should address concerns from these sources and should include the upgrades to the standard identified in Attachment C to bring the revised standard into conformance with the latest version of the ERO Rules of Procedure.

The PRC 001 standards drafting team will coordinate the transfer of monitoring related requirements to appropriate other standards through coordination with the standards drafting teams associated with project 2006-06 (Reliability Coordination)

Detailed Description

This project will address the issues identified by the System Protection and Control Task Force for the planning-related requirements in PRC-001 as well as any planning-related concerns identified in FERC Order 693. (The operations-related requirements in PRC-001 are being addressed under Project 2006-06.) A detailed listing of the areas of the existing standard that need improvement is provided in Attachment B titled “NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination”

The drafting team will also make the improvements to the standard identified in Attachment C – “Reliability Standards Review Guidelines” to bring the revised standard into conformance with the latest version of the ERO Rules of Procedure.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator Area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☒	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
MOD-011-0	Modify to include the essential data for wide-area fault studies, as noted in the attached SPCTF report on PRC-001.

Related SARs

SAR ID	Explanation
RC SAR	Project 2006-06 – Reliability Coordination includes modification of the real-time requirements but does not address the planning-related requirements.

Regional Variances

Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
SERC	None
RFC	None
SPP	None
WECC	None

SPCTF Roster

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NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination

December 7, 2006

A Technical Review of Standards

Prepared by the
System Protection and Controls Task Force
of the
NERC Planning Committee

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Appendix B — SYSTEM PROTECTION AND CONTROL TASK FORCE **9**

This report was approved by the Planning Committee on December 7, 2006, for forwarding to the Standards Committee.

Introduction

When the original scope for the System Protection and Control Task Force was developed, one of the assigned items was to review all of the existing PRC-series Reliability Standards, to advise the Planning Committee of our assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.

This report presents the SPCTF's assessment of PRC-001-0 – System Protection Coordination. The report includes the SPCTF's understanding of the intent of this standard and contains specific observations relative to the existing standard.

This standard was developed by translating the requirements of an earlier Phase I Planning Standard; thus it has not been previously subjected to a critical review of the Requirements.

Executive Summary

This reliability standard is intended to assure that system protection is coordinated between multiple transmission entities and between generation entities and transmission entities. It appears that this standard is intended to address coordination of protection functions and capabilities in both the operating time frame and the planning time frame. These time frames, as they apply to protective functions, are discussed, as are the various responsibilities to assure the related coordination.

The SPCTF concludes that the list of applicable entities in the existing standard is incomplete and that the assigned responsibilities do not reflect the activities of the identified functions. Significantly, the existing standard disregards the significant responsibilities and roles of the equipment owners; specifically, the Transmission Owners and Generator Owners.

The SPCTF also concludes that the Requirements of the existing standard are vague and ambiguous, and that, while Measures and Levels of Non-Compliance are defined, these are essentially unenforceable because of fundamental flaws within the requirements.

Assessment of PRC-001-0

General Comments

The SPCTF offers the following general comments:

1. None of the requirements within PRC-001-0 specifically indicate what protective systems are being addressed.
2. The phrase "protective relay or equipment" is a recurring phrase, and generally should be revised to "protective system" or "protective system equipment."
3. The phrase "If a protective relay or equipment failure reduces system reliability" is ambiguous, and needs additional clarification. This phrase does not clearly state when failures must be reported.
4. Many of the requirements list the Balancing Authority as an applicable entity. It does not seem that the Balancing Authority has the direct responsibility for any of these activities, and only needs to respond to the various issues when directed by the Transmission Operator and/or Generator Operator.

Applicability

4.1. Balancing Authorities
4.2. Transmission Operators

4.3. Generator Operators

The remainder of the PRC-series standards rarely assigns any responsibility for protection systems to any of the above entities. Specifically, the responsibilities for disturbance monitoring (which includes some monitoring of protective systems) and for protective system maintenance apply to the equipment owners, specifically Transmission Owners and Generator Owners. The current applicable entities do, however, have a role in the functions of this standard. The SPCTF asserts that Transmission Owner, Generator Owner, and Distribution Provider should be added to the list of Applicable Entities.

R1

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protective system schemes applied it its area.

This requirement is a statement of a highly laudable goal, but this is not specific and enforceable. In fact, the drafting team that was providing missing Measures and Compliance Elements was unable to assign either to this requirement.

It may be possible to restate this requirement in such a way to be measurable and enforceable. The protective system equipment owners (Transmission Owners, Generator Owners, and Distribution Providers) should be responsible to provide the necessary information to the Transmission Operator and Generator Operator to facilitate their familiarity with the relevant protective systems.

R2

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

Requirement R2 addresses the operating horizon, but the equipment owner entities will be familiar with the condition of their protective system equipment.

Therefore, the responsibility for this requirement must originate with the owner entities: the Transmission Owner, Generator Owner, and Distribution Provider. These entities should inform the Transmission Operator, Generator Operator, and Balancing Authorities of equipment failures pertinent to this requirement. The Transmission Operators may need to have to coordinate with each other, similar to the existing requirement R4.

The requirement for corrective action, “as soon as possible”, is vague and ambiguous, and needs modification to be specific.

As evidenced by the lack of a related Measure (via the drafting team for missing Measures and Compliance Elements), this requirement is currently not measurable.

R3

> **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
>
> **R3.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
>
> **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

Not only new protective systems and changes to protective systems should be coordinated. A requirement should be added to require coordination of all existing protective systems. Then, requirement R3 should require the coordination new protective systems and changes to protective systems with existing protective systems.

Requirement R3 addresses the planning horizon; therefore, this responsibility should be assigned to the Transmission Owner, Generator Owner, and Distribution Provider.

In addition, R3.1 should be bi-directional; the Transmission entity should provide similar coordination with the Generator entity.

R4

> **R4.** Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

It's unclear whether this requirement addresses the operations planning horizon or the planning horizon.

If Requirement R4 addresses the planning horizon, the responsibilities should be assigned similarly to the recommendations for R3, to the Transmission Owner, Generator Owner, and Distribution Provider. If Requirement R4 addresses the planning horizon, it seems to be redundant with R3 to some extent.

R5

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.

Requirement R5 addresses the both the planning horizon and operating planning horizon. It is essential to the reliability of the system that this activity occurs, and it must occur in advance of any changes to the system.

In the operations planning horizon, the Operator entities should coordinate these changes with the Owner entities, since the Owners have the tools to analyze the effects of these system changes on the protective systems and the access to the protective systems to make any needed changes to the protective system.

In the planning horizon, the owner entities should be responsible for this requirement, similarly to Requirement R3.

R6

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

Requirement R6 addresses the operating horizon. The Owners have to monitor the status of Special Protection Systems and provide the status to the Operators. The Operators then should coordinate the availability of Special Protection Systems between each other, and take any necessary operating actions to address issues with Special Protection Systems.

This requirement needs to better define "status of … Special Protection System…"

This requirement may be better moved to one of the PRC-series standards specifically addressing Special Protection Systems.

Related Standard
MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures

Also, while reviewing PRC-001, the SPCTF noted that no existing NERC Standard requires that a consistent model be maintained for protection studies, such as that required by MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures, for other steady-state studies. Without such a model, various Transmission Owners, Generator Owners, and Distribution Providers cannot accurately

apply the protective relaying. To address this deficiency, the SPCTF recommends that MOD-011, Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures, be modified to include the essential data for wide-area fault studies. The specific MOD-011 requirements are listed below, together with suggested modifications.

R1.2 – Generators
Recommend including direct-axis synchronous reactance (X_d), transient reactance (X_d'), sub transient reactance (X_d"), and the associated time constants (T_{do}, T_{do}', and T_{do}") for synchronous generators. For induction and inverter generators, generically include the data necessary to model the equipment in short circuit models in the positive, negative, and zero sequence domains.

R1.3 – Transmission Lines
Recommend specifying the positive and zero sequence impedance, including mutual impedances

R1.5 – Transformers
Recommend specifying positive sequence and zero sequence impedance, including all grounding effects.

FERC Assessment of PRC-001-0

In the October 20, 2006, the Notice of Proposed Rulemaking for adoption of NERC Standards (Docket Number RM06-16-000), the Federal Energy Regulatory Commission, for the most part, considered the operating horizon impacts of PRC-001. FERC proposed that PRC-001-0 be approved as mandatory and enforceable. They did, however, propose that NERC be directed to make modifications to PRC-001. The modifications proposed in the NOPR are excerpted from the NOPR and repeated below:

"The Commission proposes to direct that NERC submit a modification to PRC-001-0 that: (1) includes Measures and Levels of Non-Compliance; (2) includes a requirement that relevant transmission operators and generator operators must be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities can carry out the appropriate corrective control actions consistent with those used in mitigating IROL violations; and (3) clarifies that, after being informed of failures in relays or protection system elements on the Bulk-Power System, transmission operators or generator operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes."

Other Activities related to PRC-001-0

The Standard Drafting Team on Missing Measures and Compliance Elements modified PRC-001-0 as a part of their work, but the requirements were not changed. As this report is being prepared, the modified Standard is being balloted.

A draft SAR for the revision of PRC-001-0 is included in the "Draft Reliability Standards Development Plan: 2007–2009", which was presented to the NERC Board of Trustees for their approval on November 1, 2006. This draft SAR is entitled, "System Protection Project (2009-01)", and discusses many of the same deficiencies in PRC-001-1 that were identified by the SPCTF.

Conclusion and Recommendation

As it exists today, enforcement of PRC-001-0 will be very difficult. The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the "operating horizon," "operations planning horizon," and "planning horizon" protection coordination issues, the deficiencies in the current standard are magnified.

The SPCTF recommends that the existing draft Standards Authorization Request that is included in the "Draft Reliability Standards Development Plan: 2007–2009" be modified to include the observations from the SPCTF assessment of PRC-001-0 and also include the modifications directed in the FERC NOPR on RM06-16-000. The SPCTF also recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards.

In addition, it is not possible to effectively coordinate protective systems without having accurate short circuit models of neighboring systems. To address these modeling issues related to data for short circuit calculations, the SPCTF recommends that a Standards Authorization Request be developed to modify Standard MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures, to address these issues. Data for short circuit calculations, as noted in this report, should be considered as additional requirements within MOD-013-1.

Appendices

Appendix A is not relevant to this SAR and was removed

Appendix B — SYSTEM PROTECTION AND CONTROL TASK FORCE

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Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

> **High Risk Requirement**
> A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;
> or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.
>
> **Medium Risk Requirement**
> A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative

conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature; or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon
The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels
The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. (‘Violation severity levels’ replace existing ‘levels of non-compliance.’) The violation severity levels must be applied for each requirement and may be combined to cover multiple requirements, as long as it is clear which requirements are included and that all requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: more than 95% but less than 100% compliant.
- **Moderate: mostly compliant with significant exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: more than 85% but less than or equal to 95% compliant.
- **High: marginal performance or results** — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more

significant elements. Equivalent score: more than 70% but less than or equal to 85% compliant.

- **Severe: poor performance or results** — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: 70% or less compliant.

Compliance Monitor
Replace, ‘Regional Reliability Organization’ with ‘Regional Entity’

Fill-in-the-blank Requirements
Do not include any ‘fill-in-the-blank’ requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan. The effective date should be linked to the NERC BOT adoption date.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, ‘Associated Documents’.

Functional Model Version 3
Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Standard Authorization Request Form

Title of Proposed Standard	**PRC-001-1 — System Protection Coordination (Project 2007-06)**
Request Date	May 7, 2007
Revised Date	July 27, 2007

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name NERC System Protection and Control Task Force (Attachment A)	☐	New Standard
Primary Contact Charles Rogers (SPCTF Chairman)	☒	Revision to existing Standard
Telephone 517-788-0027 Fax 517-788-0917	☐	Withdrawal of existing Standard
E-mail cwrogers@cmsenergy.com	☐	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

The purpose of standard PRC-001-1 — System Protection Coordination should remain "To ensure system protection is coordinated among operating entities." The standard should be revised to:

1. Assure that Protection System application and performance issues are coordinated among all related entities.
2. Correct the applicable entities within the standard to reflect the actual functional responsibilities, as described in the NERC Functional Model.
3. Incorporate other general improvements described in the standards development work plan and from other sources.
4. Address directives received from ERO regulatory authorities.
5. Consider the observations and recommendations developed by the NERC SPCTF, which are detailed in the attached report (Attachment B), approved by the Planning Committee in December 2006.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

Protection system coordination is an absolute necessity for the North American electric system to operate properly. PRC-001 is a Version 0 standard, and was translated from an operating policy that was appropriate in an era of voluntary compliance.

The Version 0 standards and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update those standards, incorporating improvements to make the standards more suitable for enforcement.

Both FERC (within Order 693) and the SPCTF (in their report on PRC-001) identified significant shortcomings in the existing standard.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

The existing PRC-001 Standard has been identified in the Reliability Standards Development Plan as requiring revision, within the FERC Order 693 as requiring revisions, and by a SPCTF report (attached) which identified a number of issues with the existing standard (the SPCTF report, which precedes FERC Order 693, also includes observations from the preceding FERC NOPR on RM-06-16-000). This revision of PRC-001 should address concerns from these sources and should include the upgrades to the standard identified in Attachment C to bring the revised standard into conformance with the latest version of the ERO Rules of Procedure.

The PRC 001 standards drafting team will coordinate the transfer of monitoring related requirements to appropriate other standards through coordination with the standards drafting teams associated with project 2006-06 (Reliability Coordination)

Detailed Description

This project will address the issues identified by the System Protection and Control Task Force for the planning-related requirements in PRC-001 as well as any planning-related concerns identified in FERC Order 693. (The operations-related requirements in PRC-001 are being addressed under Project 2006-06.) A detailed listing of the areas of the existing standard that need improvement is provided in Attachment B titled “NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination”

The drafting team will also make the improvements to the standard identified in Attachment C – “Reliability Standards Review Guidelines” to bring the revised standard into conformance with the latest version of the ERO Rules of Procedure.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator Area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☒	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes

5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
MOD-011-0	Modify to include the essential data for wide-area fault studies, as noted in the attached SPCTF report on PRC-001.

Related SARs

SAR ID	Explanation
RC SAR	Project 2006-06 – Reliability Coordination includes modification of the real-time requirements but does not address the planning-related requirements.

Regional Variances

Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
SERC	None
RFC	None
SPP	None
WECC	None

SPCTF Roster

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NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination

December 7, 2006

A Technical Review of Standards

Prepared by the
System Protection and Controls Task Force
of the
NERC Planning Committee

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Appendix B — SYSTEM PROTECTION AND CONTROL TASK FORCE **9**

This report was approved by the Planning Committee on December 7, 2006, for forwarding to the Standards Committee.

Introduction

When the original scope for the System Protection and Control Task Force was developed, one of the assigned items was to review all of the existing PRC-series Reliability Standards, to advise the Planning Committee of our assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.

This report presents the SPCTF's assessment of PRC-001-0 – System Protection Coordination. The report includes the SPCTF's understanding of the intent of this standard and contains specific observations relative to the existing standard.

This standard was developed by translating the requirements of an earlier Phase I Planning Standard; thus it has not been previously subjected to a critical review of the Requirements.

Executive Summary

This reliability standard is intended to assure that system protection is coordinated between multiple transmission entities and between generation entities and transmission entities. It appears that this standard is intended to address coordination of protection functions and capabilities in both the operating time frame and the planning time frame. These time frames, as they apply to protective functions, are discussed, as are the various responsibilities to assure the related coordination.

The SPCTF concludes that the list of applicable entities in the existing standard is incomplete and that the assigned responsibilities do not reflect the activities of the identified functions. Significantly, the existing standard disregards the significant responsibilities and roles of the equipment owners; specifically, the Transmission Owners and Generator Owners.

The SPCTF also concludes that the Requirements of the existing standard are vague and ambiguous, and that, while Measures and Levels of Non-Compliance are defined, these are essentially unenforceable because of fundamental flaws within the requirements.

Assessment of PRC-001-0

General Comments

The SPCTF offers the following general comments:

1. None of the requirements within PRC-001-0 specifically indicate what protective systems are being addressed.
2. The phrase "protective relay or equipment" is a recurring phrase, and generally should be revised to "protective system" or "protective system equipment."
3. The phrase "If a protective relay or equipment failure reduces system reliability" is ambiguous, and needs additional clarification. This phrase does not clearly state when failures must be reported.
4. Many of the requirements list the Balancing Authority as an applicable entity. It does not seem that the Balancing Authority has the direct responsibility for any of these activities, and only needs to respond to the various issues when directed by the Transmission Operator and/or Generator Operator.

Applicability

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

The remainder of the PRC-series standards rarely assigns any responsibility for protection systems to any of the above entities. Specifically, the responsibilities for disturbance monitoring (which includes some monitoring of protective systems) and for protective system maintenance apply to the equipment owners, specifically Transmission Owners and Generator Owners. The current applicable entities do, however, have a role in the functions of this standard. The SPCTF asserts that Transmission Owner, Generator Owner, and Distribution Provider should be added to the list of Applicable Entities.

R1

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protective system schemes applied it its area.

This requirement is a statement of a highly laudable goal, but this is not specific and enforceable. In fact, the drafting team that was providing missing Measures and Compliance Elements was unable to assign either to this requirement.

It may be possible to restate this requirement in such a way to be measurable and enforceable. The protective system equipment owners (Transmission Owners, Generator Owners, and Distribution Providers) should be responsible to provide the necessary information to the Transmission Operator and Generator Operator to facilitate their familiarity with the relevant protective systems.

R2

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

Requirement R2 addresses the operating horizon, but the equipment owner entities will be familiar with the condition of their protective system equipment.

Therefore, the responsibility for this requirement must originate with the owner entities: the Transmission Owner, Generator Owner, and Distribution Provider. These entities should inform the Transmission Operator, Generator Operator, and Balancing Authorities of equipment failures pertinent to this requirement. The Transmission Operators may need to have to coordinate with each other, similar to the existing requirement R4.

The requirement for corrective action, “as soon as possible”, is vague and ambiguous, and needs modification to be specific.

As evidenced by the lack of a related Measure (via the drafting team for missing Measures and Compliance Elements), this requirement is currently not measurable.

R3

> **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
>
> **R3.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
>
> **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

Not only new protective systems and changes to protective systems should be coordinated. A requirement should be added to require coordination of all existing protective systems. Then, requirement R3 should require the coordination new protective systems and changes to protective systems with existing protective systems.

Requirement R3 addresses the planning horizon; therefore, this responsibility should be assigned to the Transmission Owner, Generator Owner, and Distribution Provider.

In addition, R3.1 should be bi-directional; the Transmission entity should provide similar coordination with the Generator entity.

R4

> **R4.** Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

It's unclear whether this requirement addresses the operations planning horizon or the planning horizon.

If Requirement R4 addresses the planning horizon, the responsibilities should be assigned similarly to the recommendations for R3, to the Transmission Owner, Generator Owner, and Distribution Provider. If Requirement R4 addresses the planning horizon, it seems to be redundant with R3 to some extent.

R5

> **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:
>
> **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.
>
> **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.

Requirement R5 addresses the both the planning horizon and operating planning horizon. It is essential to the reliability of the system that this activity occurs, and it must occur in advance of any changes to the system.

In the operations planning horizon, the Operator entities should coordinate these changes with the Owner entities, since the Owners have the tools to analyze the effects of these system changes on the protective systems and the access to the protective systems to make any needed changes to the protective system.

In the planning horizon, the owner entities should be responsible for this requirement, similarly to Requirement R3.

R6

> **R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

Requirement R6 addresses the operating horizon. The Owners have to monitor the status of Special Protection Systems and provide the status to the Operators. The Operators then should coordinate the availability of Special Protection Systems between each other, and take any necessary operating actions to address issues with Special Protection Systems.

This requirement needs to better define "status of … Special Protection System…"

This requirement may be better moved to one of the PRC-series standards specifically addressing Special Protection Systems.

Related Standard
MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures

Also, while reviewing PRC-001, the SPCTF noted that no existing NERC Standard requires that a consistent model be maintained for protection studies, such as that required by MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures, for other steady-state studies. Without such a model, various Transmission Owners, Generator Owners, and Distribution Providers cannot accurately

apply the protective relaying. To address this deficiency, the SPCTF recommends that MOD-011, Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures, be modified to include the essential data for wide-area fault studies. The specific MOD-011 requirements are listed below, together with suggested modifications.

R1.2 – Generators
Recommend including direct-axis synchronous reactance (X_d), transient reactance (X_d’), sub transient reactance (X_d”), and the associated time constants (T_{do}, T_{do}’, and T_{do}”) for synchronous generators. For induction and inverter generators, generically include the data necessary to model the equipment in short circuit models in the positive, negative, and zero sequence domains.

R1.3 – Transmission Lines
Recommend specifying the positive and zero sequence impedance, including mutual impedances

R1.5 – Transformers
Recommend specifying positive sequence and zero sequence impedance, including all grounding effects.

FERC Assessment of PRC-001-0

In the October 20, 2006, the Notice of Proposed Rulemaking for adoption of NERC Standards (Docket Number RM06-16-000), the Federal Energy Regulatory Commission, for the most part, considered the operating horizon impacts of PRC-001. FERC proposed that PRC-001-0 be approved as mandatory and enforceable. They did, however, propose that NERC be directed to make modifications to PRC-001. The modifications proposed in the NOPR are excerpted from the NOPR and repeated below:

“The Commission proposes to direct that NERC submit a modification to PRC-001-0 that: (1) includes Measures and Levels of Non-Compliance; (2) includes a requirement that relevant transmission operators and generator operators must be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities can carry out the appropriate corrective control actions consistent with those used in mitigating IROL violations; and (3) clarifies that, after being informed of failures in relays or protection system elements on the Bulk-Power System, transmission operators or generator operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes.”

Other Activities related to PRC-001-0

The Standard Drafting Team on Missing Measures and Compliance Elements modified PRC-001-0 as a part of their work, but the requirements were not changed. As this report is being prepared, the modified Standard is being balloted.

A draft SAR for the revision of PRC-001-0 is included in the “Draft Reliability Standards Development Plan: 2007–2009”, which was presented to the NERC Board of Trustees for their approval on November 1, 2006. This draft SAR is entitled, “System Protection Project (2009-01)”, and discusses many of the same deficiencies in PRC-001-1 that were identified by the SPCTF.

Conclusion and Recommendation

As it exists today, enforcement of PRC-001-0 will be very difficult. The applicable entities in the existing Standard are incorrect for many of the requirements, and the requirements themselves are vague and not measurable. In addressing the "operating horizon," "operations planning horizon," and "planning horizon" protection coordination issues, the deficiencies in the current standard are magnified.

The SPCTF recommends that the existing draft Standards Authorization Request that is included in the "Draft Reliability Standards Development Plan: 2007–2009" be modified to include the observations from the SPCTF assessment of PRC-001-0 and also include the modifications directed in the FERC NOPR on RM06-16-000. The SPCTF also recommends that the requirements for the operating horizon and planning horizon be clearly delineated and warrants consideration of dividing this standard into two standards.

In addition, it is not possible to effectively coordinate protective systems without having accurate short circuit models of neighboring systems. To address these modeling issues related to data for short circuit calculations, the SPCTF recommends that a Standards Authorization Request be developed to modify Standard MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures, to address these issues. Data for short circuit calculations, as noted in this report, should be considered as additional requirements within MOD-013-1.

Appendices

Appendix A is not relevant to this SAR and was removed

Appendix B — SYSTEM PROTECTION AND CONTROL TASK FORCE

Charles W. Rogers
Chairman / RFC-ECAR Representative
Principal Engineer
Consumers Energy Co.

W. Mark Carpenter
Vice Chairman / ERCOT Representative
System Protection Manager
TXU Electric Delivery

John Mulhausen
FRCC Representative
Manager, Design and Standards
Florida Power & Light Co.

Joseph M. Burdis
ISO/RTO Representative
Senior Consultant / Engineer, Transmission and Interconnection Planning
PJM Interconnection, L.L.C.

William J. Miller
RFC-MAIN Representative
Consulting Engineer
Exelon Corporation

Deven Bhan
MRO Representative
Electrical Engineer, System Protection
Western Area Power Administration

Philip Tatro
NPCC Representative
Consulting Engineer
National Grid USA

Philip B. Winston
SERC Representative
Manager, Protection and Control
Georgia Power Company

Fred Ipock
SPP Representative
Senior Engineer - Substations & Protection
City Utilities of Springfield, Missouri

David Angell
WECC Representative
T&D Planning Engineering Leader
Idaho Power Company

John L. Ciufo
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New York Independent System Operator

Evan T. Sage
Investor Owned Utility
Senior Engineer
Potomac Electric Power Company

James D. Roberts
Federal
Transmission Planning
Tennessee Valley Authority

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NERC Consultant
Wiedman Power System Consulting Ltd.

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Principal Electrical Engineer
American Electric Power

Baj Agrawal
WECC Alternate
Principal Engineer
Arizona Public Service Company

Michael J. McDonald
Senior Principal Engineer, System Protection
Ameren Services Company

Jonathan Sykes
Senior Principal Engineer, System Protection
Salt River Project

W. O. (Bill) Kennedy
Canada Member-at-Large
Principal
b7kennedy & Associates Inc.

Bob Stuart
NERC Blackout Investigation Team
Director of Business Development, Principal T&D Consultant
Elequant, Inc.

Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replace existing 'levels of non-compliance.') The violation severity levels must be applied for each requirement and may be combined to cover multiple requirements, as long as it is clear which requirements are included and that all requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: more than 95% but less than 100% compliant.
- **Moderate: mostly compliant with significant exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: more than 85% but less than or equal to 95% compliant.

- **High: marginal performance or results** — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: more than 70% but less than or equal to 85% compliant.
- **Severe: poor performance or results** — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: 70% or less compliant.

Compliance Monitor
Replace, 'Regional Reliability Organization' with 'Regional Entity'

Fill-in-the-blank Requirements
Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan. The effective date should be linked to the NERC BOT adoption date.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Functional Model Version 3
Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Unofficial Nomination Form

Nominations Solicited For Four Review and Drafting Teams

Please complete the electronic nomination form as soon as possible, but no later than **January 20, 2015.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form. If you have any questions, please contact Ryan Stewart.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the review or drafting team meetings if appointed by the Standards Committee. If appointed, you are expected to attend most of the face-to-face drafting team meetings as well as participate in all the team meetings held via conference calls. Failure to do so may result in your removal from the review or drafting team.

The time commitment for these projects is expected to be one face-to-face meeting a month (on average two full working days) with conference calls scheduled as needed to meet the agreed upon timeline the review or drafting team sets forth. Review and drafting teams also will have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team efforts is outreach. Members of the teams should be conducting outreach during development prior to posting to ensure all issues can be discussed and resolved.

Nominations are being sought for the following projects. Previous review or drafting team experience is beneficial but not required. A brief description of the desired qualifications and other pertinent information for each project is included below.

- Project 2015-02: Emergency Operations Periodic Review
    - *Expected 2015 August Board of Trustees presentation for adoption*
- Project 2015-03: Periodic Review of System Operating Limits Standards
    - *Expected 2015 November Board of Trustees presentation for adoption*
- Project 2015-04: Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedure (Appendix 2 of the Rules of Procedure)
    - *Expected 2015 August Board of Trustees presentation for adoption*
- Project 2007-06.2: System Protection Coordination
    - *Expected 2015 November Board of Trustees presentation for adoption*

Project 2015-02 Emergency Operations Periodic Review

The purpose of this project is to conduct a periodic review of a subset of Emergency Operations (EOP) Standards. The periodic review comprehensively reviews EOP-004, EOP-005, EOP-006, and EOP-008 to evaluate, for example, whether the requirements are clear and unambiguous. The periodic review will include background information, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be: (1) reaffirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. The four NERC Reliability Standards in this periodic review project concern methodologies for planning for, reporting, and communicating Emergencies.

Standards affected: EOP-004-2, EOP-005-2, EOP-006-2, and EOP-008-1

NERC is seeking a cross section of the industry to participate on the team, but in particular is seeking individuals who have experience and expertise with Emergency Operations program planning, reporting, and communicating across the United States and/or Canada.

Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Project 2015-03 Periodic Review of System Operating Limit Standards

The purpose of this project is to conduct a periodic review of a subset of Facilities Design, Connections, and Maintenance (FAC) Standards. The periodic review comprehensively reviews FAC-010, FAC-011, and FAC-014 to evaluate, for example, whether the requirements are clear and unambiguous. The three NERC Reliability Standards in this periodic review project concern methodologies for determining and communicating System Operating Limits. The periodic review will include background information, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be: (1) reaffirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn.

Standards affected: FAC-010-2.1, FAC-011-2, and FAC-014-2

NERC is seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who have experience and expertise with System Operating Limits methodologies, Facility Ratings, and Interconnection Reliability Operating Limits and communicating the methodologies across the United States and/or Canada.

Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Project 2015-04 Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedure (Appendix 2 of the Rules of Procedure)

The purpose of this project is to align the NERC Glossary of Terms (Glossary) and the Definitions Used in the Rules of Procedure (Appendix 2 of the Rules of Procedure). There are many inconsistencies between the defined terms contained in the Glossary and the NERC Rules of Procedure. The drafting team will be responsible for identifying inconsistencies in the defined terms, revising the defined term in order to address the inconsistencies, and posting for comment and ballot the proposed revisions to the defined terms.

The drafting team work and proposed revisions will be undertaken and in accordance with the processes outlined in the NERC Rules of Procedure, Section 1400 (“Amendments to the NERC Rules of Procedure”) and the Standard Processes Manual, Section 5 (“Process for Developing a Defined Term”).

Standards affected: None (definitions)

NERC is seeking a cross section of the industry to participate on the team, but in particular is seeking individuals who have experience with the technical nature of many of the NERC Reliability Standards across the United States and/or Canada, legal or technical writing backgrounds, and facilitation skills. Please include this in the description of qualifications as applicable.

Project 2007-06.2 System Protection Coordination

The proposed project is phase 2 of Project 2007-06 – System Protection Coordination is revising Reliability Standard PRC-001-1.1 (System Protection Coordination). Phase 1 is under the direction of the System Protection Coordination Standard Drafting Team (SPCSDT) which is proposing to incorporate PRC-001-1.1, Requirements R3 and R4 into a new Reliability Standard, PRC-027-1 (Coordination of Protection System Performance During Faults). Phase 2 will focus on revising PRC-001-1.1, Requirements R1, R2, R5, and R6 in accordance with the revisions occurring due to phase 1.

Standards affected: PRC-001-1.1

NERC is seeking a cross section of the industry to participate, but in particular is seeking industry stakeholders for participation on the standard drafting team (SDT) to revise PRC-001-1.1. The drafting team will identify the objectives required to revise PRC-001-1.1. Industry stakeholders with expertise in the communication of protection system changes in status or issues to other entities in an operating (e.g., BA, GOP, TOP, or RC) or planning role (e.g., PC or TP) and/or the instruction of operating personnel regarding the purpose and limitations of protection systems.

Please provide the following information for the nominee:	
Name:	
Title:	
Organization:	
Address:	
Telephone:	
Email:	

Select the Project(s) for which the nominee is volunteering. Nominees may check multiple projects but NERC will endeavor to place an individual on only one project if at all possible. If checking multiple projects, indicate in the space below first choice, second choice, and so on.

☐ Project 2015-02: Emergency Operations Periodic Review

☐ Project 2015-03: Periodic Review of System Operating Limit Standards

☐ Project 2015-04: Alignment of NERC Glossary of Terms (Definitions section of the Rules of Procedure)

☐ Project 2007-06.2: System Protection Coordination

Please briefly describe the nominee's experience and qualifications to serve on the selected project(s):

If you are currently a member of any NERC SAR or standard drafting team, please list each team here:

☐ Not currently on any active SAR or standard drafting team.

☐ Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any NERC SAR or standard drafting team, please identify the team(s):

☐ No prior NERC SAR or standard drafting team.

☐ Prior experience on the following SAR or standard drafting team(s):

Select each NERC Region in which you have experience relevant to Project 2010-02:		
☐ ERCOT ☐ FRCC ☐ MRO	☐ NPCC ☐ RF ☐ SERC	☐ SPP ☐ WECC ☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority ☐ Compliance Enforcement Authority ☐ Distribution Provider ☐ Generator Operator ☐ Generator Owner ☐ Interchange Authority ☐ Load-serving Entity ☐ Market Operator ☐ Planning Coordinator	☐ Transmission Operator ☐ Transmission Owner ☐ Transmission Planner ☐ Transmission Service Provider ☐ Purchasing-selling Entity ☐ Reliability Coordinator ☐ Reliability Assurer ☐ Resource Planner

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		Email:	
Name:		Telephone:	
Organization:		Email:	
Provide the names and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

Standards Announcement

Solicitation for Drafting and Review Team Nominations

Nomination Period Open through January 20, 2015

Now Available

Nominations are being sought for the projects listed below. Previous drafting or review team experience is beneficial but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information for each project is included below, and more detailed information is included on the unofficial Word version of the nomination form.

Project 2015-02 – Emergency Operations Periodic Review

The purpose of this project is to conduct a periodic review of a subset of Emergency Operations (EOP) Standards. The periodic review comprehensively reviews EOP-004, EOP-005, EOP-006, and EOP-008 to evaluate, for example, whether the requirements are clear and unambiguous. The periodic review will include background information, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be: (1) reaffirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. The four NERC Reliability Standards in this periodic review project concern methodologies for planning for, reporting, and communicating Emergencies.

Project 2015-03 – Periodic Review of System Operating Limit Standards

The purpose of this project is to conduct a periodic review of a subset of Facilities Design, Connections, and Maintenance (FAC) Standards. The periodic review comprehensively reviews FAC-010, FAC-011, and FAC-014 to evaluate, for example, whether the requirements are clear and unambiguous. The three NERC Reliability Standards in this periodic review project concern methodologies for determining and communicating System Operating Limits. The periodic review will include background information, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be: (1) reaffirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn.

Project 2015-04 – Alignment of NERC Glossary of Terms (Definitions section of the Rules of Procedure)

The purpose of this project is to align the NERC Glossary of Terms (Glossary) and the Definitions Used in the Rules of Procedure (Appendix 2 of the Rules of Procedure). There are many inconsistencies between the defined terms contained in the Glossary and the NERC Rules of Procedure. The drafting team will be responsible for identifying inconsistencies in the defined terms, revising the defined term in order to address the inconsistencies, and posting for comment and ballot the proposed revisions to the defined terms.

The drafting team work and proposed revisions will be undertaken in accordance with the processes outlined in the NERC Rules of Procedure, Section 1400 ("Amendments to the NERC Rules of Procedure") and the Standard Processes Manual, Section 5 ("Process for Developing a Defined Term").

Project 2007-06.2 – System Protection Coordination

The proposed project is phase 2 of Project 2007-06 – System Protection Coordination is revising Reliability Standard PRC-001-1.1 (System Protection Coordination). Phase 1 is under the direction of the System Protection Coordination Standard Drafting Team (SPCSDT) which is proposing to incorporate PRC-001-1.1, Requirements R3 and R4 into a new Reliability Standard, PRC-027-1 (Coordination of Protection System Performance During Faults). Phase 2 will focus on revising PRC-001-1.1, Requirements R1, R2, R5, and R6 in accordance with the revisions occurring due to phase 1.

Instructions for Submitting Nominations

Please complete and submit the electronic nomination form. Please do not submit multiple forms; one nominee may volunteer for more than one project on a single form by indicating the order of preference within the form. An unofficial version of the nomination form is provided for convenience in compiling the necessary information.

Next Steps

The Standards Committee is expected to begin appointing drafting and review teams for these projects in January 2015. Nominees will be notified shortly after they have been appointed to a drafting or review team.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Ryan Stewart,
Manager of Standards Development, or at 404.446.9697.

North American Electric Reliability Corporation
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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Unofficial Nomination Form

Project 2007-06.2 Phase 2 of System Protection Coordination Standard Drafting Team

Do not use this form to submit nominations. Use the electronic form to submit nominations for additional members of the standard drafting team (SDT). The electronic form must be submitted by **8 p.m. Eastern, Tuesday, February 9, 2016.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Documents and information about this project are available on the Project 2007-06.2 Phase 2 of System Protection Coordination page. If you have questions, contact Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the review or drafting team meetings if appointed by the Standards Committee. If appointed, you are expected to attend most of the face-to-face drafting team meetings, as well as those held via conference calls.

The time commitment for these projects is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Drafting teams will also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team efforts is outreach. Members of the team should be conducting outreach during development prior to posting to ensure all issues can be discussed and resolved.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Background

This solicitation for nominations is to supplement the Phase 2 System Protection Coordination SDT with individuals experienced in training. The current SDT is addressing Requirements R1, R2, R5, and R6 of PRC-001-1.1(ii). The current SDT is considering addressing Requirement R1 of PRC-001-1.1(ii) through requirements to provide training. Therefore, NERC is supplementing the SDT with subject matter experts with experience in the Personnel, Performance, Training, and Qualifications (PER) standard.

NERC is seeking individuals from the United States and Canada who possess experience in one or more of the following areas:

- Systematic approach to training
- Operations and/or operations planning background
- Personnel Performance, Training, and Qualifications (“PER”) family of Reliability Standards

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):

If you are currently a member of any NERC drafting team, list each team here:

☐ Not currently on any active SAR or standard drafting team.

☐ Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any NERC drafting team, identify the team(s):

☐ No prior NERC SAR or standard drafting team.

☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:

☐ Texas RE	☐ NPCC	☐ SPP RE
☐ FRCC	☐ RF	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs and ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	
Provide the names and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2007-06.2 Phase 2 of System Protection Coordination

Nomination Period Open through February 9, 2016

Now Available

Nominations are being sought for additional standard drafting team (SDT) members, as explained below, through **8 p.m. Eastern, Tuesday, February 9, 2016**.

Use the electronic form to submit a nomination. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the SDT meetings if appointed by the Standards Committee. If appointed, you are expected to attend most of the face-to-face meetings, as well as those held via conference calls.

The time commitment for this project is expected to be up to two face-to-face meetings per quarter (on average three full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the SDT sets forth. Drafting teams also may have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the SDT effort is outreach. Members of the team should be conducting outreach during development prior to posting to ensure all issues can be addressed.

Background

This solicitation for nominations is to supplement the Phase 2 System Protection Coordination SDT with individuals experienced in training. The current SDT is addressing Requirements R1, R2, R5, and R6 of PRC-001-1.1(ii). The current SDT is considering addressing Requirement R1 of PRC-001-1.1(ii) through requirements to provide training. Therefore, NERC is supplementing the SDT with subject matter experts with experience in the Personnel, Performance, Training, and Qualifications (PER) standards.

NERC is seeking individuals from the United States and Canada who possess experience in one or more of the following areas:

- Systematic approach to training
- Operations and/or operations planning background
- Personnel Performance, Training, and Qualifications (“PER”) family of Reliability Standards

Next Steps

The Standards Committee may appoint members to the team as early as March 2016. Nominees will be notified shortly after they have been appointed.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Scott Barfield-McGinnis (via email), or at (404) 446-9689.

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404-446-2560 | www.nerc.com

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

The System Protection Coordination (Phase 2) Standard Drafting Team (SPCP2SDT) is addressing Requirements R1, R2, R5, and R6 of PRC-001-1.1(ii). The PER-006-1 Reliability Standard addresses the Generator Operator (GOP) that is applicable to Requirement R1 of PRC-001-1.1(ii).

Requirements R1, R2, and R5 applicable to the GOP are proposed for retirement as described below.

1. The PER-006-1, Requirement R1, applicable to the GOP, is proposing to replace PRC-001-1.1(ii), Requirement R1 to address the reliability objective of being “familiar with the purpose and limitations of Protection Systems” for the GOP’s plant operator personnel. The standard PER-005-2 already addresses centrally located dispatch center personnel.
2. The Personnel Performance, Training, and Qualifications (PER) set of Reliability Standards and Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards address the reliability objective of PRC-001-1.1(ii), Requirements R2 and R5.

Requirements R1 and R6 applicable to the Balancing Authority (BA) and Requirements R1, R2, R5, and R6 applicable to the Transmission Operator (TOP) are proposed for retirement on the following basis.

1. The TOP/IRO sets of Reliability Standards address the reliability objective of these requirements.
2. The revisions to the definitions of “Operational Planning Analysis” (OPA) and “Real-time Assessment” (RTA), that the TOP and the Reliability Coordinator perform, address the reliability objective of integrating the function and limits of Protection Systems and Remedial Action Schemes (RAS) into their OPA and RTA.

See the Project 2007-06.2 mapping document for explanation on how the PER and TOP/IRO sets Reliability Standards and the revision of the two definitions address the reliability objectives of PRC-001-1.1(ii), Requirements R1, R2, R5, and R6 for the BA and TOP. The PRC-027-1 (*Coordination of Protection System Performance During Faults*) Reliability Standard addresses Requirements R3 and R4 of PRC-001-1.1(ii).

The PER-006-1 Reliability Standard and revisions to the definitions of OPA and RTA are being posted for an initial 45-day formal comment period with a concurrent initial ballot to be held in the last ten days of the comment period.

Completed Actions	Date
Standard Authorization Request (SAR) posted for comment	June 11 – July 10, 2007
SAR approved by Standards Committee (SC)	August 13, 2007
SC authorized posting of TOP-009-1	July 28, 2015
Draft 1, TOP-009-1, posted for a 45-day formal comment period	July 29 – September 11, 2015
Draft 1, TOP-009-1, concurrent/parallel initial ballot in the last ten days of the comment period	September 2-11, 2015
Draft 2, TOP-009-1, posted for a 45-day formal comment period	October 6 – November 19, 2015
Draft 2, TOP-009-1, concurrent/parallel additional ballot in the last ten days of the comment period	November 10-19, 2015
Draft 2, TOP-009-1 withdrawn from development at SDT meeting	February 9, 2016
SC authorized posting of PER-006-1	March 9, 2016

Anticipated Actions	Date
Draft 1, PER-006-1, 45-day formal comment period with initial ballot	March 2016
10-day final ballot	May 2016
NERC Board (Board) adoption	August 2016

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):
None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material section of the standard.

A. Introduction

1. **Title:** **Specific Training for Personnel**
2. **Number:** **PER-006-1**
3. **Purpose:** To ensure that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the Bulk Electric System.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Generator Operator that has:
       - **4.1.1.1.** Plant personnel who are responsible for the Real-time control of a generator and receive Operating Instruction(s) from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center.
5. **Effective Date:** See Implementation Plan for Project 2007-06.2.

B. Requirements and Measures

Rationale for Requirement R1: Protection Systems and Remedial Action Schemes (RAS) are an integral part of reliable Bulk Electric System (BES) operation. This requirement addresses the reliability objective of ensuring that the Generator Operator (GOP) plant operating personnel understand the operational functionality of Protection Systems and RAS and their effects on generating Facilities.

R1. Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies) it operates. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M1. Each Generator Operator shall have available for inspection, evidence that the applicable personnel completed training. This evidence may be documents such as training records showing successful completion of training that includes training materials, the name of the person, and date of training.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Generator Operator shall keep data or evidence of Requirement R1 for the current year and three previous calendar years.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

<table>
<tr><th rowspan="2">R #</th><th colspan="4">Violation Severity Levels</th></tr>
<tr><th>Lower VSL</th><th>Moderate VSL</th><th>High VSL</th><th>Severe VSL</th></tr>
<tr><td>R1.</td>
<td>The Generator Operator failed to provide training as described in Requirement R1 to the greater of:
one applicable personnel at a single Facility, or
5% or less of the total applicable personnel of the Generator Operator.</td>
<td>The Generator Operator failed to provide training as described in Requirement R1 to the greater of:
two applicable personnel at a single Facility, or
more than 5% and less than or equal to 10% of the total applicable personnel of the Generator Operator.</td>
<td>The Generator Operator failed to provide training as described in Requirement R1 to the greater of:
three applicable personnel at a single Facility, or
more than 10% and less than or equal to 15% of the total applicable personnel of the Generator Operator.</td>
<td>The Generator Operator failed to provide training as described in Requirement R1 to the greater of:
five or more applicable personnel at a single Facility, or
more than 15% of the total applicable personnel of the Generator Operator.
OR

The Generator Operator failed to provide training as described in Requirement R1 to its applicable personnel.</td></tr>
</table>

D. Regional Variances

None.

E. Associated Documents

Project 2007-06.2 Implementation Plan[1]

[1]http://www.nerc.com/pa/Stand/Project200706_2SystemProtectionCoordinationDL/Project_2007_06_2_Imp_Plan_Draft_1_2016_03_10_Clean.pdf

Version History

Version	Date	Action	Change Tracking
1		Adopted by the NERC Board of Trustees	New standard developed under Project 2007-06.2

Guidelines and Technical Basis

Requirement R1

The Generator Operator (GOP) monitors and controls its generating Facilities in Real-time to maintain reliability. To accomplish this, plant personnel responsible for Real-time control and operation of a generating Facility must understand how Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility. This standard requires GOPs to train their plant personnel on these issues. The standard only applies to plant operating personnel associated with the specific Facility to which they have Real-time control. This does not include other plant personnel not responsible for Real-time control (e.g., fuel or coal handlers, electricians, machinists, or maintenance staff).

A periodicity for training is not specified in Requirement R1 because it is incumbent upon the GOP to ensure its plant personnel that have Real-time control and operation of a generator are trained in order to operate the plant. The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service. On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS.

The phrase “operational functionality” focuses the training on how Protection Systems operate and prevent possible damage to Elements. It also addresses how RAS detects pre-determined BES conditions and automatically takes corrective actions.

Considerations for operational functionality may include, but is not limited to the following:

- Purpose of protective relays and RAS
- Zones of protection
- Protection communication systems (e.g., line current differential, direct transfer trip, etc.)
- Voltage and current inputs
- Station dc supply associated with protective functions
- Resulting actions – tripping/closing of breakers; tripping of a generator step-up (GSU) transformer; or generator ramping/tripping control functions

Requirement R1 focuses on the operational functionality of Protection Systems and Remedial Action Schemes specific to the generating plant and not the Bulk Electric System.

This requirement focuses on those systems that are related to the electrical output of the generator. Protective systems which trip breakers serving station auxiliary loads (e.g., such as pumps, fans, or fuel handling equipment) are not included in this training. Furthermore, protection of secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not in the scope of this training, even if a trip of these devices might eventually result in a trip of the generating unit.

~~A. Introduction~~

1. ~~**Title:** **System Protection Coordination**~~

2. ~~**Number:** PRC-001-1.1(ii)~~

3. ~~**Purpose:**~~

~~To ensure system protection is coordinated among operating entities.~~

4. ~~**Applicability**~~

~~**4.1.** Balancing Authorities~~

~~**4.2.** Transmission Operators~~

~~**4.3.** Generator Operators~~

5. ~~**Effective Date:**~~

~~See the Implementation Plan for PRC-001-1.1(ii).~~

ORANGE TEXT – Retirements of R1, R2, R5, and R6 occurring under Project 2007-06.2.

RED TEXT – Retirements of R3 and R4 occurring under Project 2007-06.

~~B. Requirements~~

~~**R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.~~

~~**R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:~~

~~**R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.~~

~~**R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.~~

~~**R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.~~

~~**R3.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.~~

- ~~Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.~~

~~**R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.~~

~~**R4.** Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.~~

~~**R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:~~

~~**R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.~~

~~**R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.~~

~~**R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.~~

~~C. Measures~~

~~**M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.~~

~~**M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)~~

~~**M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)~~

~~D. Compliance~~

~~1. Compliance Monitoring Process~~

~~1.1. Compliance Monitoring Responsibility~~

~~Regional Reliability Organizations shall be responsible for compliance monitoring.~~

~~1.2. Compliance Monitoring and Reset Time Frame~~

~~One or more of the following methods will be used to assess compliance:~~

- ~~Self-certification (Conducted annually with submission according to schedule.)~~
- ~~Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)~~
- ~~Periodic Audit (Conducted once every three years according to schedule.)~~
- ~~Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance.~~

~~1.3. Data Retention~~

~~Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.~~

~~Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.~~

~~If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.~~

~~Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,~~

~~The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.~~

~~1.4. Additional Compliance Information~~

~~None.~~

~~2. Levels of Non-Compliance for Generator Operators:~~

~~**2.1. Level 1:** Not applicable.~~

~~**2.2. Level 2**: Not applicable.~~

~~**2.3. Level 3**: Not applicable.~~

~~**2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.~~

~~3. Levels of Non-Compliance for Transmission Operators:~~

~~**3.1. Level 1:** Not applicable.~~

~~**3.2. Level 2**: Not applicable.~~

~~**3.3. Level 3**: Not applicable.~~

~~**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**3.4.1** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.~~

~~**3.4.2** Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.~~

~~**4. Levels of Non-Compliance for Balancing Authorities:**~~

~~**4.1. Level 1:** Not applicable.~~

~~**4.2. Level 2**: Not applicable.~~

~~**4.3. Level 3**: Not applicable.~~

~~**4.4. Level 4:** Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.~~

~~E. Regional Differences~~

~~None identified.~~

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~0~~	~~April 1, 2005~~	~~Effective Date~~	~~New~~
~~0~~	~~August 8, 2005~~	~~Removed "Proposed" from Effective Date~~	~~Errata~~
~~0~~	~~August 25, 2005~~	~~Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0~~	~~Errata~~
~~1~~	~~November 1, 2006~~	~~Adopted by the NERC Board of Trustees~~	~~Revised~~
~~1.1~~	~~April 11, 2012~~	~~Errata adopted by the Standards Committee; (Capitalized "Protection System" in accordance with Implementation Plan for Project 2007-17 approval of revised definition of "Protection System")~~	~~Errata associated with Project 2007-17~~
~~1.1~~	~~September 9, 2013~~	~~Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.~~	

~~1.1(i)~~	~~November 13, 2014~~	~~Adopted by the NERC Board of Trustees~~	~~Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS~~
~~1.1(ii)~~	~~February 12, 2015~~	~~Adopted by the NERC Board of Trustees~~	~~Standard revised in Project 2014-01:~~ ~~Applicability revised to clarify application of requirements to BES dispersed power producing resources~~
~~2~~	~~May 9, 2012~~	~~Adopted by Board of Trustees~~	~~Deleted Requirements R2, R5, and R6.~~
~~1.1(ii)~~	~~May 29, 2015~~	~~FERC Letter Order in Docket No. RD15-3-000 approving PRC-001-1.1(ii)~~	~~Modifications to adjust the applicability to owners of dispersed generation resources.~~

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Rationale for the Applicability Exclusion in Requirement R3.1~~

~~Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the~~

~~transmission protective systems, as this coordination would not provide reliability benefits to the BES.~~

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Proposed Definitions

Project 2007-06.2 Phase 2 of System Protection Coordination

Introduction

The following definitions are proposed for revision under the Project 2007-06.2 – Phase 2 of System Protection Coordination. The definitions of Operational Planning Analysis (OPA) and Real-time Assessment (RTA) are used in the Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards.[1] To address the reliability objective PRC-001-1.1(ii) – Protection System Coordination, Requirement R1 to be familiar with the limits of Protection System schemes, the two definitions are being modified to include the phrase "…functions, and limits…" to ensure the Transmission Operator (TOP), and Reliability Coordinator (RC) that is not applicable to PRC-001-1.1(ii), consider the functions and limits of Protection Systems and Remedial Action Schemes in their evaluations. The reliability objective is addressed by revising the definitions to require the RC and the TOP to integrate the functions and limits (i.e., purpose and limitations) into its OPA and RTA to ensure that the Bulk Electric System is operated within System Operating Limits and Interconnection Reliability Operating Limits.

Proposed Definitions

This section includes the two modified terms used in the Reliability Standards and requirements below that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms that are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard PER-006-1 – Specific Training for Personnel in order to completely retire PRC-001-1.1(ii).

Term(s):

These two terms are not found within the proposed PER-006-1 standard, but are an integral part of the basis for the retirement of PRC-001-1.1(ii), Requirement R1. There are two significant revisions.

1. An administrative update to replace "Special Protection System" to "Remedial Action Scheme."
2. The addition of the phrase "…functions, and limits…" to address the reliability objective of PRC-001-1.1(ii), Requirement R1 for the applicable TOP that must integrate the "functions and limits" into these evaluations. The proposed definition revision also has an effect on the RC that is not applicable to PRC-001-1.1(ii). The bold text in the definitions below accentuate the proposed revisions.

[1] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order No. 817, 153 FERC ¶ 61,178 (2015).

Operational Planning Analysis (OPA)
An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to**:** load forecasts; generation output levels; Interchange; known Protection System and **Remedial Action Scheme** status or degradation**, functions, and limits**; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Real-time Assessment (RTA)
An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load**;** generation output levels**;** known Protection System and **Remedial Action Scheme** status or degradation**, functions, and limits;** Transmission outages**;** generator outages**;** Interchange**;** Facility Ratings**;** and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Implementation Plan

Project 2007-06.2 Phase 2 of System Protection Coordination

Requested Approvals

- PER-006-1 – Specific Training for Personnel
- Definition of "Operational Planning Analysis"
- Definition of "Real-time Assessment"

Requested Retirements

- PRC-001-1.1(ii) – System Protection Coordination[1]

Prerequisite Approvals

- PRC-027-1 – Coordination of Protection Systems for Performance During Faults

Applicable Entities

- Generator Operator (applicable to PER-006-1 only)
- Reliability Coordinator (applicable to definitions only)
- Transmission Operator (applicable to definitions only)

General Considerations

There are a number of factors that influence the determination of the implementation period for the proposed standard and revised definitions. The following factors address the Balancing Authority, Generator Operator, and Transmission Operator:

1. The effort and resources by the Generator Operator to provide training to plant personnel to address the operational functionality of Protection Systems and Remedial Action Schemes at individual generating Facilities in PER-006-1 that the Generator Operator may not have been addressing under PRC-001-1.1(ii), Requirement R1.

2. Maintain consistency with the Implementation Plan of the approved Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards[2] that are applicable to the Balancing Authority and Transmission Operator. This

[1] The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of both proposed Reliability Standards PRC-027-1 and PER-006-1, and the proposed definitions for "Operational Planning Analysis" and "Real-time Assessment." NERC is proposing the complete retirement of PRC-001-1.1(ii) in the implementation plans associated with both PRC-027-1 and PER-006-1. The Project 2007-06 System Protection Coordination Mapping Document shows how PRC-027-1 addresses requirements R3 and R4 of PRC-001-1.1(ii). The remaining requirements of PRC-001-1.1(ii) – Requirements R1, R2, R5, and R6 are proposed for retirement in Project 2007-6.2 Phase 2 of System Protection Coordination (see the Mapping Document for Project 2007-06.2 Phase 2 of System Protection Coordination).
[2] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order No. 817, 153 FERC ¶ 61,178 (2015).

project explains how the retirement of PRC-001-1.1(ii) Requirements R1, R2, R5, and R6 are addressed by the TOP/IRO sets standards.

3. Maintaining consistency with the Implementation Plan of the approved TOP/IRO standards[3] that are applicable to the Balancing Authority and Transmission Operator in the application of the revised definitions of “Operational Planning Analysis” and “Real-time Assessment” (effective January 1, 2017) in the *NERC Glossary of Term Used in NERC Reliability Standards*. See the Project 2007-06.2 Mapping Document for additional details.

4. The amount of time needed by the Transmission Operator in PRC-001-1.1(ii), Requirement R1 and Reliability Coordinator (not applicable to PRC-001-1.1(ii)) to train on Protection Systems and Remedial Action Schemes in order to be capable of integrating their functions and limits into their Operational Planning Analysis and Real-time Assessment.

Effective Dates

PER-006-1 – Specific Training for Personnel

Reliability Standard PER-006-1 – Specific Training for Personnel shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Operational Planning Analysis and Real-time Assessment

The definitions “Operational Planning Analysis” (OPA) and “Real-time Assessment” (RTA) shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the definitions are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a definition to go into effect. Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirements

PRC-001-1.1(ii) – System Protection Coordination
Requirement R1

PRC-001-1.1(ii) – System Protection Coordination, Requirement R1 shall be retired at midnight of the day immediately prior to the effective date of PER-006-1 (*Specific Training for Personnel*) and the revised definitions of “Operational Planning Analysis” (OPA) and “Real-time Assessment” (RTA), or as otherwise provided for by an applicable governmental authority.

[3] Id.

Requirement R2, R5, and R6

PRC-001-1.1(ii) – System Protection Coordination, Requirement R2, R5, and R6 shall be retired at midnight of March 31, 2017, or as otherwise provided for by an applicable governmental authority.

Requirements R3 and R4

See Project 2007-06 System Protection Coordination Implementation Plan.[4]

Retirement of Existing Standards and Definitions

The currently-approved definitions of "Operations Planning Analysis" and "Real-time Assessment" shall be retired at midnight of the day immediately prior to the effective date of the revised definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA), or as otherwise provided for by an applicable governmental authority.

[4] http://www.nerc.com/pa/Stand/Project%20200706%20System%20Protection%20Coordination%20DL/Implementation_Plan_PRC-027-1_clean_10012015.pdf

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Unofficial Comment Form

Project 2007-06.2 Phase 2 of System Protection Coordination

Do not use this form for submitting comments. Use the electronic form to submit comments on **PER-006-1 – Specific Training for Personnel** and the two proposed modified definitions of **"Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA)**. The electronic form must be submitted by **8 p.m. Eastern, Monday, April 25, 2016.**

Documents and information about this project are available on the Project 2007-06.2 Phase 2 of System Protection Coordination project page. If you have questions, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at 404-446-9689.

Background Information

In conjunction with Project 2007-06 System Protection Coordination (Phase 1), NERC is proposing the complete retirement of PRC-001-1.1(ii). Requirements R1, R2, R5, and R6 are proposed for retirement in Project 2007-6.2 Phase 2 of System Protection Coordination. See the Mapping Document for an explanation of how the reliability objectives of those requirements are addressed by other standards, the proposed PER-006-1 – Specific Training for Personnel, and the proposed modified definitions of OPA and RTA. The remaining two Requirements R3 and R4 of PRC-001-1.1(ii) are addressed by PRC-027-1 – Coordination of Protection Systems for Performance During Faults. Details for Phase 1 are found on the 2007-06 project page. The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of PRC-027-1 (under Phase 1) as well as the proposed Reliability Standard, PER-006-1 and the proposed definition modifications of OPA and RTA (under Phase 2). NERC is proposing the retirement of PRC-001-1.1(ii) in the implementation plans associated with both projects.

Phase 1 (2007-06)

The System Protection Coordination Standard Drafting Team developed a new Reliability Standard, PRC-027-1 to address coordination of Protection System performance during Faults. This standard incorporates and clarifies the Protection System coordination aspects of Requirements R3 and R4 contained in PRC-001-1.1 that is proposed for complete retirement.

Phase 2 (2007-06.2)

Phase 2 is addressing the remaining Requirements R1, R2, R5, and R6 of PRC-001-1.1(ii). See the Mapping Document for a complete explanation on how the reliability objectives of Requirements R1, R2, R5, and R6 are addressed by other standards, the modified definitions of OPA and RTA, and the proposed PER-006-1 Reliability Standard.

Standard(s) Affected – PER-006-1, Retirement of PRC-001-1.1 (ii)

Questions

1. **Generator Operator:** Do you agree that the proposed PER-006-1 – Specific Training for Personnel appropriately replaces the responsibilities of the Generator Operator in PRC-001-1.1(ii) – System Protection Coordination, Requirement R1 (i.e., "…be familiar with the purpose and limitations of Protection Systems schemes…")? If not, please explain and provide suggestions to improve the PER-006-1 requirement.

   ☐ Yes
   ☐ No

   Comments:

2. **Transmission Operator:** The reliability objective of PRC-001-1.1(ii), Requirement R1 for the Transmission Operator (i.e., "…be familiar with the purpose and limitations of Protection Systems schemes…"), that is not already covered by the *Personnel Performance, Training, and Qualifications* (PER) Reliability Standards, is addressed by inserting the phrase "functions, and limits" into the proposed modified definitions of OPA and RTA. The Transmission Operator, by integrating the "functions and limits" of Protection Systems and Remedial Action Schemes into its OPA and RTA, will ensure that the Bulk Electric System is operated within System Operating Limits (SOL) and Interconnection System Operating Limits (IROL). Do you agree that the proposed modification of these terms as defined by the *Glossary of Terms Used in NERC Reliability Standards* achieves this reliability objective? If not, please explain and provide suggestions.

   ☐ Yes
   ☐ No

   Comments:

3. **Reliability Coordinator:** During the progression of Project 2007-06.2, it was determined that the Reliability Coordinator, a function that is not applicable to PRC-001-1.1(ii) should, similarly, "…be familiar with the purpose and limitations of Protection Systems schemes…" as found in Requirement R1 of the standard. The reliability objective for the Reliability Coordinator that is not already covered by the PER Reliability Standards, is being addressed by inserting the phrase "functions, and limits" into the proposed modified definitions of OPA and RTA. The Reliability Coordinator, by integrating the "functions and limits" of Protection Systems and Remedial Action Schemes into its OPA and RTA, will ensure that the Bulk Electric System is operated within SOL and IROL. Do you agree that the proposed modification of these terms as defined by the *Glossary of Terms Used in NERC Reliability Standards* achieves this reliability objective? If not, please explain and provide suggestions.

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with the proposed Violation Risk Factor (VRF) and Violation Severity Levels (VSLs) for the proposed PER-006-1 Requirement? If not, please provide a basis for revising the VRF and/or what would improve the clarity of the VSLs.

   ☐ Yes
   ☐ No

   Comments:

5. Do the PER-006-1, Application Guidelines provide sufficient guidance, basis for approach, and examples to support performance of the Requirement? If not, please provide specific detail that would improve the Application Guidelines.

   ☐ Yes
   ☐ No

   Comments:

6. Do you agree with implementation period (i.e., 12 months) of the proposed PER-006-1 Reliability Standard and the proposed definition modifications of OPA and RTA based on the considerations listed in the Implementation Plan? If not, please provide a justification for changing the proposed implementation periods.

   ☐ Yes
   ☐ No

   Comments:

7. Are you aware of any conflicts between the proposed PER-006-1 Reliability Standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If so, please identify the conflict here.

   ☐ Yes
   ☐ No

   Comments:

8. Are you aware of the need for a regional variance or business practice that should be considered with this project? If so, please identify it here.

   ☐ Yes
   ☐ No

   Comments:

9. If you have any other comments not previously mentioned above, please provide them here:

   Comments:

Violation Risk Factors and Violation Severity Level Justifications

Project 2007-06.2 Phase 2 of Protection System Coordination
PER-006-1 – Specific Training for Personnel

This document provides the Protection System Coordination Phase 2 Standard Drafting Team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for the proposed PER-006-1 – Specific Training for Personnel.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability

to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System: [2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

[1] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] *Id*. at footnote 15.

Guideline (3) — Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels,[3] FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance[4]

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties[5]

Guideline 2a: A violation of a “binary” type requirement must be a “Severe” VSL.

Guideline 2b: Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement[6]

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations[7]

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

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[3] *Order on Violation Severity Levels Proposed by the Electric Reliability Organization*, 123 FERC ¶61,284 (2008).

[4] *Id*. at P20

[5] *Id*. at P22

[6] *Id*. at P32

[7] *Id*. at P35

VRF Justifications – PER-006-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	In this requirement, each Generator Operator (GOP) is required to train its plant personnel on the operational functionality of Protection Systems and Remedial Action Schemes that affect output of a generating Facility. It is unlikely that this requirement in the planning time frame, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, a violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. The PRC-001-1.1(ii), Requirement R1 that will be replaced by PER-006-1, Requirement R1 has a VRF of High. The VRF of High is associated with the performance of the Balancing Authority (BA) and Transmission Operator (TOP) as they have a greater responsibility for ensuring reliable operation of the bulk electric system. The requirement for these entities to be familiar with the purpose and limitations of Protection System schemes in its area is addressed by the Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards and various requirements identified in the project mapping document. These requirements are appropriately assigned VRFs of Medium and High, therefore, does not require the GOP to also have a VRF of High. The Medium VRF is consistent with the training Requirements in the PER-005-2 (*System Personnel Training*) Reliability Standard, which includes the GOP, BA, TOP, and Reliability Coordinator.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This Requirement is consistent with the intent of Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.

VRF Justifications – PER-006-1, Requirement R1	
Proposed VRF	**Medium**
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The Requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The Requirement with a Medium VRF is consistent with the training Requirements in PER-005-1 and PER-005-2 that will become effective July 1, 2016.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: A VRF of Medium is consistent with the NERC VRF definition because GOP plant personnel could gain knowledge of the operational functionality of Protection Systems and Remedial Action Schemes that affect output of a generating Facility without specific training. It is unlikely that this requirement in the planning time frame, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, a violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This Requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

Proposed VSL – PER-006-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • one applicable personnel at a single Facility, or • 5% or less of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • two applicable personnel at a single Facility, or • more than 5% and less than or equal to 10% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • three applicable personnel at a single Facility, or • more than 10% and less than or equal to 15% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • five or more applicable personnel at a single Facility, or • more than 15% of the total applicable personnel of the Generator Operator. **OR** The Generator Operator failed to provide training as described in Requirement R1 to its applicable personnel.

VSL Justifications – PER-006-1, Requirement R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is a gradated VSL for partial performance from a Lower to High VSL and a VSL of Severe for severe or complete failure of the Requirement.

VSL Justifications – PER-006-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The currently effective PRC-001-1.1(ii) did not have VSLs assignments. The proposed VSLs do not lower the current level of compliance because they are consistent with the approved PER-005-2, Requirement R6 for which PER-006-1, Requirement R1 is based upon.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This Requirement has a binary component and utilizes a VSL of Severe for complete failure in addition to incremental VSLs for partial performance. The VSLs provide a non-preferential way to apply violation levels to both small and large entities. Violations may be assessed at the greater of the number of personnel at the plant level or a percentage of personnel at the entity level. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the corresponding Requirement, and is therefore consistent with the Requirement.

VSL Justifications – PER-006-1, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

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Mapping Document

Project 2007-06.2 Phase 2 of System Protection Coordination

Revisions or Retirements to Already Approved Standards

This mapping document explains how each of the existing Requirements (R1, R2, R5, and R6) of PRC-001-1.1(ii) (*System Protection Coordination*)[1] are being revised or retired. If a requirement is being proposed for revision, the revised, new, and/or supporting requirement(s) will be identified in the center column. If a requirement is being proposed for retirement, the center column will describe the proposed action and any requirement(s) used to support the action. Revisions and retirements will be accompanied by an explanation or justification listed in the right column. Capitalized terms, unless otherwise noted, are those found in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary").[2] References to regulatory directives are specifically related to Order No. 693 ("Order").[3] Standards or definitions listed as "existing" are enforceable and those listed as "approved" have been adopted by the NERC Board of Trustees and approved by the Federal Energy Regulatory Commission ("FERC"). Check the NERC website for effective dates. The functional entities discussed in the mapping document are the Balancing Authority (BA), Generator Operator (GOP), Planning Coordinator (PC), Reliability Coordinator (RC), Transmission Operator (TOP), and Transmission Planner (TP). The term "TOP/IRO" refers to the Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) sets of Reliability Standards that were filed under NERC Project 2014-03 – Revisions to TOP and IRO Standards[4] and approved by FERC.[5] The explanation herein assumes that the term, "Special Protection

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[1] Federal Energy Regulatory Commission (FERC) approved PRC-001-1.1(ii), effective May 29, 2015.
[2] *Glossary of Terms Used in NERC Reliability Standards*. December 7, 2015. (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).
[3] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[4] http://www.nerc.com/pa/Stand/Pages/Project-2014-03-Revisions-to-TOP-and-IRO-Standards.aspx
[5] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order 817, 153 FERC ¶ 61,178 (November 19, 2015).

System"[6] (SPS) will be replaced by the term "Remedial Action Scheme"[7] (RAS). In the referenced Reliability Standards herein the term SPS may be replaced by RAS; therefore, the term RAS will be used in the "Comments" column throughout.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing)[8,9] **R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of	PRC-001-1.1(ii), Requirement R1 is proposed for retirement. Being "familiar with the purpose and limitations of Protection System schemes"	**Introduction** The reliability objective of PRC-001-1.1(ii), Requirement R1 is to ensure that the BA, GOP, and TOP are "familiar with the purpose

[6] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Special Protection System is defined as "[a]n automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme."

[7] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), the proposed definition of Remedial Action Scheme is defined as "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as: Meet requirements identified in the NERC Reliability Standards; Maintain Bulk Electric System (BES) stability; Maintain acceptable BES voltages; Maintain acceptable BES power flows; Limit the impact of Cascading or extreme events." See definition for additional information on the definition of RAS.

[8] Order No. 693 at P 1418. "Protection and Control systems (PRC) on Bulk-Power System elements are an integral part of reliable grid operation. Protection systems are designed to detect and isolate faulty elements on a system, thereby limiting the severity and spread of system disturbances, and preventing possible damage to protected elements. The function, settings and limitations of a protection system are critical in establishing SOLs and IROLs. The PRC Reliability Standards apply to transmission operators, transmission owners, generator operators, generator owners, distribution providers and regional reliability organizations and cover a wide range of topics related to the protection and control of power systems."

[9] Order No. 693 at P 1435. "Protection systems on Bulk-Power System elements are an integral part of reliable operations. They are designed to detect and isolate faulty elements on a power system, thereby limiting the severity and spread of disturbances and preventing possible damage to protected elements. If a protection system can no longer perform as designed because of a failure of its relays, system reliability is reduced or threatened. In deriving SOLs and IROLs, moreover, the functions, settings, and limitations of protection systems are recognized and integrated. Systems are only reliable when protection systems perform as designed. This is what PRC-001-1 means in linking a reduction in system reliability with a protection relay failure or other equipment failure."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Protection System schemes applied in its area. **Operational Planning Analysis (Approved)** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and	will be clarified as (1) being "familiar with their purpose," and (2) being "familiar with their limitations" as follows: • The phrase "Protection systems schemes" maps to the NERC Glossary terms of Protection Systems and Remedial Action Schemes. • Being "familiar with the purpose" is addresses by existing and proposed training standards. • Being "familiar with the limitations" together with the clarification found in Order No. 693 at P 1418 and P 1435 along with the revised definitions of NERC Glossary defined terms of Operational Planning	and limitations of Protection System[12] schemes applied in its area." The reliability objective of the phrase "Protection System schemes" in PRC-001-1.1(ii), Requirement R1 is also intended to include RAS. The function, settings and limitations of a Protection Systems and RAS are critical in establishing System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL) such that the Bulk Electric System[13] (BES) is operated within these limits. The following explains how being familiar with the purpose and limitations of Protection Systems and RAS will be

[12] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Protection System is defined as:
"Protection System -
- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."

[13] See *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Real-time Assessment (Approved)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)	Analysis and Real-time Assessment address the reliability objective of PRC-001-1.1(ii), Requirement R1 as explained in the Comments column to the right. **PER-006-1 (New)** **4.** Applicability: **4.1.** Functional Entities: **4.1.1.** Generator Operator that have: **4.1.1.1.** Plant personnel who are responsible for the Real-time control of a generator and receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center. This does not include personnel at a centrally located dispatch center. **R1.** Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the	addressed according to issue beginning with "familiarity with their limitations" and then "familiarity with their purpose." **Familiar with their limitations** When the BA, GOP, and TOP are familiar with the settings and limits (i.e., limitations) of Protection Systems and RAS, the entities are able to operate the BES in such a manner that Protection Systems and RAS will be operated within their limits and be able to detect and isolate faulty Elements, thereby, limiting the severity and spread of system disturbances, and preventing possible damage to protected Elements. When the GOP is familiar with the limitations of Protection Systems and RAS by being trained on how Protection Systems operate and prevent possible damage to Elements, the GOP is capable of operating to its full capability within its area, meaning the output of its generation Facilities. When the BA is familiar with the limitations of Protection Systems and RAS, it is capable

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	operational functionality of Protection Systems and Remedial Action Schemes that affect output of a generating Facility. **PER-003-1 (Existing)** **R1.** Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate: **1.1.** Areas of Competency **1.1.1.** Resource and demand balancing **1.1.2.** Transmission operations **1.1.3.** Emergency preparedness and operations **1.1.4.** System operations **1.1.5.** Protection and control **1.1.6.** Voltage and reactive	of maintaining generation, Load, and Interchange balance. The BA ensures that RAS in its area are enabled when needed for system reliability. When the TOP is familiar with limitations of Protection Systems and RAS, it will be capable of identifying when system reliability is reduced or threatened. In operating to established SOLs and IROLs, it is important that the functions, settings, and limitations of Protection Systems and RAS are recognized and integrated by the TOP into operating the BES reliably. The BES is only reliable when Protection Systems and RAS perform within their limitations. **Familiarity with the Purpose** Familiarity with the purpose of Protection Systems and RAS is achieved through training as explained below according to each applicable entity. **Familiarity with the Purpose (GOP)**

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	1.1.7. Interchange scheduling and coordination **1.1.8.** Interconnection reliability operations and coordination **R2.** Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates: **2.1.** Areas of Competency **2.1.1.** Transmission operations **2.1.2.** Emergency preparedness and operations **2.1.3.** System operations **2.1.4.** Protection and control **2.1.5.** Voltage and reactive **2.2.** Certificates • Reliability Operator	For the GOP, the Reliability Standard PER-006-1 (*Specific Training for Personnel*) proposes to replace PRC-001-1.1(ii), Requirement R1. The PER-006-1 standard identifies applicable GOP personnel that are responsible for the Real-time control of a generator and that receive Operating Instructions from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center. This applicability removes ambiguity over which personnel of the GOP are intended to be familiar with the purpose Protection Systems and RAS. Centrally located personnel are not included here because they are addressed by PER-005-2 (*Operations Personnel Training*). Personnel at centrally located dispatch centers will receive company-specific Protection System and RAS training, if identified, as a reliability-related task via the PER-005-2, Requirement R6. Here the GOP must use "...a systematic approach to develop and implement training to its personnel identified in Applicability

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	• Balancing, Interchange and Transmission Operator • Transmission Operator **R3.** Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificate: **3.1.** Areas of Competency **3.1.1.** Resources and demand balancing **3.1.2.** Emergency preparedness and operations **3.1.3.** System operations **3.1.4.** Interchange scheduling and coordination **3.2.** Certificates • Reliability Operator	Section 4.1.5.1. of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations.” Being trained using a systematic approach on the purpose (i.e., functions, including limits) Protection Systems and RAS will enable the GOP centrally located dispatch personnel to ensure reliable operation of its Facilities on the BES. The phrase “…purpose and limitations…” in PRC-001-1-1(ii), Requirement R1 is addressed in the proposed requirement through the use of “operational functionality.” The phrase “operational functionality” as described in the PER-006-1 – Application Guidelines describes that training is expected to cover how Protection Systems operate within their limits and prevent possible damage to Elements. It also addresses how RAS detect pre-determined BES conditions and automatically take corrective actions. The criteria that comprises operational functionality mirror

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	• Balancing, Interchange and Transmission Operator • Balancing and Interchange Operator **PER-005-2 (Approved)** **R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: **1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.	the components listed under the NERC Glossary term "Protection System." By doing so, reduces the ambiguity of the phrase "purpose and limitations." The phrase "…applied in its area" is addressed by the PER-006-1 by using "…that affect output of a generating Facility." Lastly, the proposed PER-006-1 Requirement R1 includes both Protection Systems and RAS to eliminate confusion over the phrase "Protection System schemes." **Familiarity with the Purpose (BA)** For the BA, the PRC-001-1.1(ii), Requirement R1 is proposed for retirement on the basis that the BA obtains an appropriate level of familiarity with the purpose of Protection Systems and RAS under PER-003-1 (*Operating Personnel Credentials*), Requirement R3 and PER-005-2, Requirements R1, R3, R4, and R5 as explained below in detail.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	1.2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1. **1.3.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program. **1.4.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.	The BA is certified under PRC-003-1 as a System Operator.[14] Although there is no specific area of competency for protection and control similar to the Reliability Coordinator and Transmission Operator certifications, the NERC *Balancing and Interchange Operator Certification Exam Content Outline 2015*[15] (BI Exam) does contain the same five topics applicable to RC and less one topic applicable to the TOP. The topic that is not included is to "analyze relay targets, fault locaters and fault recorders to determine a proper restoration plan" and is not germane to BA operations. The job-task analyses (JTA) performed by entities are used to (1) develop the BI Exam topics that are evaluated by NERC and a NERC functional entity working group every three years, and (2) used to develop the training of

[14] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a System Operator is defined as: An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System (BES) in Real-time.

[15] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Balancing%20and%20Interchange%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	R2. (Omitted – Transmission Owner, not applicable) **R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1. or Requirement R2 part 2.1. **3.1.** Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in	personnel on company-specific reliability-related tasks under PER-005-2. Protection and control topics are addressed in the BI Exam outline under two areas: System Operations and Emergency Preparedness and Operations, and include the following five topics: • Analyze the impact of protection equipment outages on system reliability. • Ensure special protective systems and remedial action schemes are enabled when needed for system reliability. • Maintain adequate protective relaying during all phases of the system restoration. • Take action in response to alarms from special protective schemes. • Schedule system telecommunications, telemetering, protection, and control equipment outages to ensure system reliability.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Requirement R1 part 1.1. or Requirement R2 part 2.1. **R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. **4.1.** A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously	There is a fourth certification that includes an integrated certification of both the BA and TOP called the *Balancing, Interchange, and Transmission Operator Certification Exam Content Outline 2015*[16] (BIT Exam). This BIT Exam outline does include protection and control as an area of competency and contains the same topics found in the *Transmission Operator Certification Exam Content Outline 2015*. Under PER-005-2, the System Operator and Operation Support Personnel of the BA are identified in the requirements. To address the reliability objective of "shall be familiar with the purpose and limitations of Protection System schemes applied in its area," the BA uses its JTA to develop a list of its reliability-related tasks. Using its documented methodology, the BA must develop and implement training materials

[16] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Balancing%20Interchange%20Transmission%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria. **R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. **5.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training. **R6.** Each Generator Operator shall use a systematic approach to develop and	according to its training program (R1) using a systematic approach to training. The BA is required to verify the capabilities of its System Operators under Requirement R3. Under Requirement R4, the BA "that (1) has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1[17] with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES." Requirement R5 addresses the Operations Support Personnel of the BA, which requires the BA to use a systematic approach to develop and implement training for its identified Operations Support Personnel on

[17] Requirement R2 is omitted here because it is applicable to the Transmission Owner and is not within the scope of this project.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	implement training to its personnel identified in Applicability Section 4.1.5.1. of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. **6.1.** Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training. **Operational Planning Analysis (OPA) (Revised)** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and **Remedial Action Scheme** (status or	how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 that are applicable to System Operators. **Familiarity with the Purpose (TOP)** The TOP will ensure that the BES is operated within SOLs and IROLs by integrating the "functions and limits" of Protection Systems and RAS into its OPA and RTA as proposed by the revisions to the definitions of OPA and RTA. For the TOP, the PRC-001-1.1(ii), Requirement R1 is proposed for retirement on the basis that the TOP obtains a sufficient level of knowledge (i.e. be familiar with the purpose of Protection System schemes applied in its area) under PER-003-1 (*Operating Personnel Credentials*), Requirement R1 and PER-005-2,

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	degradation**, functions, and limits**; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)[10] **Real-time Assessment (RTA) (Revised)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and **Remedial Action Scheme (**status or degradation**, and functions, and limits)**, Transmission outages, generator outages,	Requirements R1, R3, R4, and R5, as explained below in detail. The TOP is certified as a System Operator, and has an "area of competency" for "protection and control" as shown in the NERC *Transmission Operator Certification Exam Content Outline 2015*.[18] This represents a minimum competency in the area of protection and control. However, certified System Operators will receive company-specific training on Protection Systems and RAS through PER-005-2, Requirements. The job-task analyses (JTA) performed by entities are used to (1) develop the BI Exam topics that are evaluated by NERC and a NERC functional entity working group every three years, and (2) used to develop the training of personnel

[10] Bolded text identifies the proposed revisions.
[18] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Transmission%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)[11] **IRO-008-2 (Approved)** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its	on company-specific reliability-related tasks under PER-005-2. Under PER-005-2, System Operator and Operation Support Personnel of the TOP are identified in the requirements. To address the reliability objective of "shall be familiar with the purpose and limitations of Protection System schemes applied in its area," the TOP uses its JTA to develop a list of its reliability-related tasks. Using its documented methodology, the TOP must develop and implement training materials according to its training program (R1) using a systematic approach to training. The TOP is required to verify the capabilities of its System Operators under Requirement R3. Under Requirement R4, the TOP "that (1) has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall

[11] Bolded text identifies the proposed revisions.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	provide its personnel identified in Requirement R1[19] with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES." Requirement R5 addresses the Operations Support Personnel of the TOP, which requires the TOP to use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1. Operations Support Personnel are among the personnel that perform Operational Planning Analyses (OPA) and Real-time Assessments (RTA). These reliability-related-tasks, include performing both an OPA and RTA and are

[19] Requirement R2 is omitted here because it is applicable to the Transmission Owner and is not within the scope of this project.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	IRO-010-2 (Approved) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.1.** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data.	proposed for modification to address the integration of Protection System and RAS limits to ensure the BES is operated within SOLs and IROLs. See the discussion below concerning the OPA and RTA for the explanation of how the revised definitions support the reliability object objective of PRC-001-1.1(ii), Requirement R1. **Reliability Coordinator (RC)** The standard PRC-001-1.1(ii) did not include the RC as an applicable functional entity; however, the RC is included here to further support the explanation on how the RC, along with the TOP, ensures the BES is operated within SOLs and IROLs by integrating the limits of Protection Systems and RAS into its OPA and RTA. The RC obtains a sufficient level of knowledge (i.e. be familiar with the purpose and limitations of Protection System schemes applied in its area) under PER-003-1 (*Operating Personnel Credentials*),

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	1.4. The deadline by which the respondent is to provide the indicated data. **TOP-001-3 (Approved)** **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **TOP-002-4 (Approved)** **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its	Requirement R1 and PER-005-2, Requirements R1, R3, R4, and R5. The RC is certified as a System Operator, and has an "area of competency" for "protection and control" as shown in the NERC *Reliability Coordinator Certification Exam Content Outline 2015*.[20] This represents a minimum competency in the area of protection and control. However, certified System Operators will receive company-specific training on Protection Systems and RAS through PER-005-2, Requirements. Under PER-005-2, System Operator and Operation Support Personnel of the RC are identified in the requirements. To similarly address the reliability objective of "shall be familiar with the purpose and limitations of Protection System schemes applied in its area" in PRC-001-1.1(ii), Requirement R1, the RC uses its JTA to develop a list of its

[20] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Reliability%20Coordinator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **R3.** Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).	reliability-related tasks. Using its documented methodology, the RC must develop and implement training materials according to its training program (R1) using a systematic approach to training. The RC is required to verify the capabilities of its System Operators under Requirement R3. Under Requirement R4, the RC that (1) has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1[21] with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES." Requirement R5 addresses the Operations Support Personnel of the RC, which requires the RC to use a systematic approach to develop and implement training

[21] Requirement R2 is omitted because it is applicable to the Transmission Owner and is not within the scope of this project.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
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		for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1. Operations Support Personnel are among the personnel that perform Operational Planning Analyses (OPA) and Real-time Assessments (RTA). These reliability-related tasks include performing both an OPA and RTA and are proposed for modification to address the integration of Protection System and RAS limits to ensure the BES is operated within SOLs and IROLs. See the discussion below concerning the OPA and RTA for the explanation of how the revised definitions support the reliability object objective of PRC-001-1.1(ii), Requirement R1. **Operational Planning Analysis (OPA)** The TOP, applicable to PRC-001-1.1(ii), Requirement R1, is required have an OPA that will allow it to assess whether its

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		planned operations for the next day within its Transmission Operator Area will exceed any of its SOLs (TOP-002-4, Requirement R1). The TOP is required to have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified as a result of its OPA as required in Requirement R1 (TOP-002-4, Requirement R2) and notify others of their role in the Operating Plan(s) (TOP-002-4, Requirement R4). To accomplish this the TOP is required to maintain a documented data specification for the data necessary to perform its OPA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts System reliability (TOP-003-3, Requirement R1, Part 1.2.). The RC is not applicable to PRC-001-1.1(ii) and is included here for additional support. The RC is required to perform an OPA that will allow it to assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area (IRO-008-2,

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		Requirement R1). The RC is required to have a coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances identified as a result of its OPA as performed in Requirement R1 (IRO-008-2) while considering the Operating Plans for the next-day provided by its TOPs and BAs (IRO-008-2, Requirement R2). To accomplish this the RC is required to maintain a documented data specification for the data necessary to perform its OPA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts System reliability (IRO-010-2, Requirement R1, Part 1.2.). **Real-time Assessment (RTA)** The TOP, applicable to PRC-001-1.1(ii), Requirement R1, is required ensure that an RTA is performed at least once every 30 minutes (TOP-001-3, Requirement R13). The TOP is required initiate its Operating Plan to mitigate a SOL exceedance identified as part

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		of its RTA (TOP-001-3, Requirement R14). To accomplish this the TOP is required to maintain a documented data specification for the data necessary to perform its RTA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts System reliability (TOP-003-3, Requirement R1, Part 1.2.). The RC is not applicable to PRC-001-1.1(ii) and is included here for additional support. The RC is required to ensure that a RTA is performed at least once every 30 minutes (IRO-008-4, Requirement R4). The RC is required notify impacted Transmission Operators and Balancing Authorities within its RC Area, and other impacted RCs as indicated in its Operating Plan, when the results of a RTA indicate an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area (IRO-008-2, Requirement R5). To accomplish this the RC is required to maintain a documented data specification

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		for the data necessary to perform its RTA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts System reliability (IRO-010-2, Requirement R1, Part 1.2.).
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its	PRC-001-1.1(ii), Requirements R2, R2.1., and R2.2. are proposed for retirement. The subsequent sections are organized in the following manner: • Corrective Action, • Time Frame for corrective actions • Time Frame for notifications, • Shall notify, and • Protection System Inputs for notification	**Introduction** **Requirement PRC-001-1.1(ii), Requirement R2** The reliability objective of Requirement R2 and its sub-requirements ensure that the GOP and TOP take corrective action, as soon as possible, if a protective relay or equipment failure reduces system reliability. The subsequent explanation provides detail on how the TOP/IRO set of Reliability Standards (e.g., IRO-001-4, IRO-008-2, IRO-010-2, TOP-001-3, and TOP-003-3) that were developed since the Order was issued achieve the reliability objectives of PRC-001-

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Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.		1.1(ii), Requirement R2 and its sub-requirements. **Directives** Included in the explanation below is how these Reliability Standards address the directives in the Order at P 1441, 1444, 1445 and 1449 (#2 and #3). **Other** Additionally, PER-005-3, Requirements R7 and R8 include RAS to ensure full coverage of the "operational functionality." The phase "relay or equipment" in PRC-001-1.1(ii), Requirement R2 is clarified by the use of the defined NERC Glossary term, "Protection System" and "RAS."
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	PRC-001-1.1(ii), Requirements R2, R2.1., and R2.2. are proposed for retirement. Corrective action in Requirements R2, R2.1. and R2.2. is covered by:	**Introduction – Corrective Action** The directive at P 1449 (#3) of the Order states that: "…transmission operators must carry out corrective control actions, i.e., return a system to a stable state that

Standard: PRC-001-1.1(ii) – System Protection Coordination		
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R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**TOP-001-3 (Approved)** **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. **R2.** Each Balancing Authority shall act to maintain the reliability of its Balancing	respects system requirements…" This directive is addressed in the TOP/IRO standards that were developed since the Order was issued because the BA, RC, and TOP can issue Operating Instructions[22] to maintain the reliability of its respective area. The following describes how the TOP/IRO Reliability Standards achieve the reliability objective with regard to "corrective actions." **Corrective Action by the GOP – R2.1.** TOP-003-3 (*Operations Reliability Data*) Requirement R1 and part 1.2. that was developed since the Order was issued addresses corrective action by the GOP because the TOP will be aware of current Protection System and SPS status (change in status is implied) or degradation (including failure) that impacts System reliability. See

[22] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Operating Instruction is defined as "[a] command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)"

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PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the	Authority Area via its own actions or by issuing Operating Instructions. **TOP-003-3 (Approved)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data	the "shall notify" section(s) below for a full description of how the TOP receives such notification. TOP-001-3 (*Transmission Operations*) Furthermore, the TOP will act to maintain the reliability of its Transmission Operator Area[23] (TOP Area) by issuing Operating Instructions to the GOP under TOP-001-3, Requirement R1. TOP-003-3 (*Operations Reliability Data*) Similarly, TOP-003-3, Requirement R2 and part 2.2. that was developed since the Order was issued addresses corrective action by the GOP because the BA (i.e., Host BA[24]) will be aware of current Protection System and SPS status (change in status is implied) or

[23] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Transmission Operator Area is defined as "[t]he collection of Transmission assets over which the Transmission Operator is responsible for operating."

[24] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Host Balancing Authority is defined as:

1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries.
2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.

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Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible. **PRC-001-1.1(ii) (Existing)** **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the BA receives such notification. The BA will act to maintain the reliability of its Balancing Authority Area[25] (BA Area) by issuing Operating Instructions to the GOP under TOP-001-3, Requirement R2. **Corrective Action by the TOP – R2.2.** TOP-003-3 (*Operations Reliability Data*) Requirement R1 and part 1.2. that was developed since the Order was issued addresses corrective action by the TOP because the TOP will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full

[25] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Balancing Authority Area is defined as "[t]he collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area."

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R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible. **PRC-001-1.1(ii) (Existing)** **R2.** Each Generator Operator and Transmission Operator shall notify reliability		description of how the TOP receives such notification. TOP-001-3 (*Transmission Operations*) The TOP will act to maintain the reliability of its TOP Area by issuing Operating Instructions under TOP-001-3, Requirement R2. TOP-003-3 (*Operations Reliability Data*) Similarly, TOP-003-3, Requirement R2 and part 2.2. that was developed since the Order was issued addresses corrective action by the BA because the BA will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the TOP receives such notification. The BA will act to maintain the reliability of its BA Area by issuing Operating Instructions under TOP-001-3, Requirement R2.

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entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**IRO-010-2 (Approved)** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **IRO-001-4 (Approved)** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions."	IRO-010-2 (*Reliability Coordinator Data Specification and Collection*) Requirement R1 and part 1.2. that was developed since the Order was issued addresses corrective action by the RC because the RC will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the RC receives such notification. IRO-001-4 (*Reliability Coordination - Responsibilities and Authorities*) Under Requirement R1, the RC will act to address the reliability of its Reliability Coordinator Area[26] (RC Area) by issuing Operating Instructions.

[26] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Balancing Authority Area is defined as "[t]he collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas."

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Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	PRC-001-1.1(ii), Requirements R2, R2.1, and R2.2. are proposed for retirement. The time frame for corrective action in Requirements R2, R2.1. and R2.2. is covered by:	**Introduction – Time frame for corrective actions** The directive at P 1441 directs the ERO to clarify the term "corrective action" consistent with the discussion in the Order when it modifies PRC-001-1 in the Reliability Standards development process. The reasoning for addressing a time frame for corrective actions is amplified in P 1443 of the Order, which states that: "As explained above *[in the previous paragraphs of the Order*], the requirement for system operators to take corrective control action when protective relay or equipment failure reduces system reliability should be treated the same as the requirement for returning a system to a secure and reliable state after an Interconnection Reliability Operating Limit (IROL) violation, i.e., as soon as possible, but no longer than 30 minutes after a violation. A longer time limit would place an entity in

Standard: PRC-001-1.1(ii) – System Protection Coordination		
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R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected		violation of relevant IROL or TOP Reliability Standards."[27] At P 1444 of the Order, FERC directed NERC to consider the comments of the California PUC regarding the term "as soon as possible" as applicable to the maximum time frame for corrective action through the Standards development process. At P 1445 of the Order, FERC directed NERC, through the Reliability Standards development process, to determine the appropriate amount of time after the detection of relay failures, in which relevant transmission operators must be informed of such failures. The Order at P 1449 (#3) directs NERC to clarify that, after being informed of failures in relays or protection system elements that threaten reliability of the Bulk-Power

[27] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Interconnection Reliability Operating Limit is defined as "[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System."

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Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**TOP-001-3 (Approved)** **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.	System, transmission operators must carry out corrective control actions, i.e., return a system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes after they receive notice of the failure. **PRC-001-1.1(ii), R2.1. & R2.2. (time frame for corrective actions)** For the reasons explained below, a less than one-hour time frame criteria for corrective action will achieve the reliability objective directed in the Order at P 1441, 1444, 1445, and 1449 (#2 and #3). TOP-001-3 (*Transmission Operations*) Requirement R13 requires the TOP to ensure that a Real-time Assessment[28] ("RTA") is performed at least once every 30 minutes

[28] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Real-time Assessment is defined as "[a]n evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)"

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.	**R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.	and initiate its Operating Plan[29] to mitigate a System Operating Limit[30] (SOL) exceedance identified as part of its Real-time[31] monitoring or RTA in TOP-001-3, Requirement R14. The RTA requires inputs to include current Protection System and RAS status (change in status is implied) or degradation (including failure) from a BA, GOP, and/or TOP. Under TOP-003-3 notification of these inputs must occur within a 30 minute time frame; otherwise, an RTA cannot be performed once every 30 minutes.

[29] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Operating Plan is defined as "[a] document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan."

[30] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a System Operating Limit is defined as "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)"

[31] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), Real-time is defined as "[p]resent time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)"

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Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**IRO-008-2 (Approved)** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **TOP-003-3 (Approved)** **R1.** Each Transmission Operator shall maintain a documented specification for the	Given the periodicity for obtaining the data and performing the RTA, the exposure (i.e., time frame) for taking corrective action "as soon as possible" is expected to be less than an hour. The TOP may issue Operating Instructions to maintain reliability upon the notification of Protection System or RAS status (change in status is implied) or degradation (including failure) because the exposure is not expected to exceed an hour. The TOP must act under TOP-001-3, Requirement R1 to maintain the reliability of its TOP Area via its own actions or by issuing Operating Instructions. IRO-008-2 (*Reliability Coordinator Operational Analyses and Real-time Assessments*), Requirement R4 requires the RC to ensure that an RTA is performed at least once every 30 minutes. The RTA requires inputs to include current Protection System and RAS status (change in status is implied) or degradation (including failure) from a BA, GOP, and/or TOP.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **IRO-010-2 (Approved)** **R1.** The Reliability Coordinator shall maintain a documented specification for the	TOP-003-3 (*Operations Reliability Data*) IRO-010-2 (*Reliability Coordinator Data Specification and Collection*) Under TOP-003-3 (TOP and BA) and IRO-010-2 (RC) notification of these inputs must occur within a 30 minute time frame; otherwise, an RTA cannot be performed once every 30 minutes. Given the periodicity for obtaining the data and performing the RTA, the exposure (i.e., time frame) for taking corrective action as soon as possible is expected to be less than an hour. The RC may issue Operating Instructions to maintain reliability upon the notification of Protection System or RAS status (change in status is implied) or degradation (including failure) because the exposure is not expected to exceed an hour.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **IRO-001-4 (Approved)** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.	IRO-001-4 (*Reliability Coordination - Responsibilities and Authorities*) The RC must act under IRO-001-4, Requirement R1 to maintain the reliability of its RC Area via its own actions or by issuing Operating Instructions.
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the	PRC-001-1.1(ii), Requirements R2, R2.1., and R2.2 are proposed for retirement. The time frame for notification in Requirements R2, R2.1. and R2.2. is covered by:	**Introduction – Time frame for notifications and shall notify** The directive at P 1444 of the Order directed NERC to consider the comments of FirstEnergy about the time frame between actual failure and its discovery (i.e., notification) in relation to the maximum time frame for corrective action through the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**IRO-008-2 (Approved)** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **TOP-001-3 (Approved)** **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **TOP-003-3 (Approved)**	Standards development process. The Order at P 1445 and 1449 (#2) directed NERC to determine an appropriate amount of time after the detection of relay failures and the time in which relevant generation and transmission operators must be informed of such failure. **PRC-001-1.1(ii), R2.1. & R2.2. (time frame for notifications)** TOP-001-3 (*Transmission Operations*) For the reasons explained below concerning notification, it is inferred that the timeframe for notification must occur on at least a 30 minute interval because the a RTA performed by the RC (IRO-008-2) and TOP (TOP-001-3) once every 30 minutes requires the data to be availability on at least a 30 minute basis such that the exposure is less than one hour.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its	**R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R3.** Each Transmission Operator shall distribute its data specification to entities	TOP-003-3 (*Operations Reliability Data*) Notification in PRC-001-1.1(ii), Requirement R2.1. and R2.2. is addressed by TOP-003-3, Requirement R1, part 1.2. for TOP and Requirement R2, part 2.2. for BA that were developed since the Order was issued. Requirements R1 and R2 mandate that the TOP and BA to have provisions (i.e., inputs) for notification of Protection System and RAS status (change in status is implied) or degradation (including failures) that impacts System reliability. **PRC-001-1.1(ii), R2.1. (shall notify)** Based on the conclusions above (i.e., “time frame for corrective actions”), notifications of the inputs of Protection Systems and RAS by the GOP must be provided on at least a 30-minute basis. The TOP/IRO set of standards that were developed since the Order was issued achieve the reliability objective of ensuring that the BA (i.e., Host BA) and TOP are notified of protective relay and equipment failures.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible. **PRC-001-1.1(ii) (Existing)** **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing	that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. **R4.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring. **R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: **5.1.** A mutually agreeable format	TOP-003-3 (*Operations Reliability Data*) TOP-003-3, Requirement R1 mandates the TOP have a documented specification for the data necessary for the TOP to perform an Operational Planning Analysis ("OPA"),[32] Real-time monitoring, and RTA. Both the OPA and RTA, by definition, require an evaluation that reflects inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure). TOP-003-3, Requirement R3 mandates the TOP distribute its documented specification to those entities that have the required data, which includes the GOP. TOP-003-3, Requirement R2 mandates the BA have a documented specification for the data necessary for the BA to perform its analysis functions and Real-time monitoring that include inputs from Protection System

[32] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Operational Planning Analysis is defined as "[a]n evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**5.2.** A mutually agreeable process for resolving data conflicts **5.3.** A mutually agreeable security protocol. **TOP-003-3 (Approved) (included again for reference)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis	and RAS status (change in status is implied) or degradation that are necessary to maintain generation-Load-Interchange balance. TOP-003-3, Requirement R4 mandates the BA to distribute its documented specification to those entities that have the required data, which includes the GOP. TOP-003-3, Requirement R5 builds upon the previous Requirements R1, R2, R3, and R4 described above. Requirement R5 mandates that any GOP that receives a data specification (pursuant to Requirement R3 or R4) to satisfy the obligations of the documented specifications using: a mutually agreeable format, a mutually agreeable process for resolving data conflicts, and a mutually agreeable security protocol. Therefore, the reliability objective of PRC-001-1.1(ii) Requirement R2, R2.1 that mandates the GOP notify its TOP and Host BA of protective relay and equipment failures is addressed by the documented

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.	specification for the data required in TOP-003-3, Requirement R1, part 1.2. for TOP and Requirement R2, part 2.2. for the BA. The documented data specifications is required to be distributed by the TOP and BA and mandates the GOP per TOP-003-3, Requirement R5 provide current Protection System and RAS status (change in status is implied) or degradation that impacts System reliability. **PRC-001-1.1(ii), R2.2. (shall notify)** Based on the conclusions above (i.e., "time frame for corrective actions), notifications of the inputs of Protection Systems and RAS by the TOP must be provided on at least a 30-minute basis. The TOP/IRO set of standards that were developed since the Order was issued achieve the reliability objective of ensuring that the RC and the BA and TOP (i.e., the affected BA and TOP) are notified of protective relay and equipment failures. TOP-003-3 (*Operations Reliability Data*)

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	TOP-003-3 (Approved) (included again for reference) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection	TOP-003-3, Requirement R1, mandates the TOP have a documented specification for the data necessary for the TOP to perform an OPA, Real-time monitoring, and RTA. Both the OPA and RTA, by definition, require an evaluation to reflect inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure). TOP-003-3, Requirement R3 mandates the TOP distribute its documented specification to those entities that have the required data, which includes the BA, RC, and TOP. TOP-003-3, Requirement R2 mandates the BA have a documented specification for the data necessary for the BA to perform its analysis functions and Real-time monitoring, which would include inputs from Protection System and RAS status (change in status is implied) or degradation that are necessary to maintain generation-Load-Interchange balance. TOP-003-3, Requirement R4 mandates the BA distribute its documented specification to those entities that have the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	System status or degradation that impacts System reliability. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. **IRO-010-2 (Approved)** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	required data, which includes the BA, RC, and TOP. TOP-003-3, Requirement R5 builds upon the previous Requirements R1, R2, R3, and R4 described above. Requirement R5 mandates that any TOP that receives a data specification (pursuant to Requirement R3 or R4) to satisfy the obligations of the documented specifications using: a mutually agreeable format, a mutually agreeable process for resolving data conflicts, and a mutually agreeable security protocol. **Common to both the GOP and TOP** IRO-010-2 (*Reliability Coordinator Data Specification and Collection*) Requirement R1, mandates the RC have a documented specification for the data necessary for the RC to perform an OPA, Real-time monitoring, and RTA. Both the OPA and RTA, by definition, require an evaluation to reflect inputs from known Protection System and RAS status (change in status is implied) or degradation (including

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	failure). IRO-010-2, Requirement R2 mandates the RC distribute its documented specification to those entities that have the required data, which includes the BA, RC, and TOP. IRO-010-2, Requirement R3 builds upon the previous Requirements R1 and R2 described above. Requirement R3 mandates that a TOP that receives a data specification (pursuant to Requirement R2) to satisfy the obligations of the documented specifications using: a mutually agreeable format, a mutually agreeable process for resolving data conflicts, and a mutually agreeable security protocol. Therefore, the reliability objective of PRC-001-1.1(ii) Requirement R2, R2.2. that mandates the TOP to notify its RC and affected BA and TOP of protective relay and equipment failures is addressed by the documented specification for the data required in TOP-003-3, Requirement R1, part 1.2. for TOP and Requirement R2, part 2.2.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		for the BA, and IRO-010-2, Requirement R1 for the RC. The documented data specifications is required to be distributed by the TOP and will require the RC per IRO-010-2, Requirement R3 and the BA and TOP per TOP-003-3, Requirement R5 to provide current Protection System and RAS status (change in status is implied) or degradation that impacts System reliability.
PRC-001-1.1(ii) (Existing) **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows. **R3.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. • Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified	**PRC-027-1 (NERC Board approved)** The mapping of PRC-001-1.1(ii), Requirements R3, R3.1 and R3.2 are addressed in a different project. See Project 2007-06 System Protection Coordination (i.e., Phase 1) concerning proposed Reliability Standard PRC-027-1.	N/A

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
through Inclusion I4 of the Bulk Electric System definition. **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.		
PRC-001-1.1(ii) (Existing) **R4.** Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	**PRC-027-1 (NERC Board approved)** The mapping of PRC-001-1.1(ii), Requirement R4 is addressed in a different project. See Project 2007-06 System Protection Coordination (i.e., Phase 1) concerning proposed Reliability Standard PRC-027-1.	N/A
PRC-001-1.1(ii) (Existing) **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating	PRC-001-1.1(ii), Requirements R5, R5.1, and R5.2 are proposed for retirement. The notification in advance in Requirements R5, R5.1 and R5.2 is covered by:	**Introduction – Shall notify in advance** For the reasons explained under the “shall notify” sections above, the TOP will receive notifications of known current Protection Systems and RAS status (change in status is

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
conditions that could require changes in the Protection Systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems. **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	**TPL-001-4 (Existing)** **R4.** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance	implied) or degradation (including failure) from the GOP and TOP under TOP-003-3 that was developed since the Order was issued. Advance notification to the TOP will occur through IRO-008-2, IRO-017-1 (*Outage Coordination*), and TOP-002-4 (*Operations Planning*) that were developed since the Order was issued, and through the existing TPL-001-4 (*Transmission System Planning Performance Requirements*). **PRC-001-1.1(ii), R5.1 and R5.2 (shall notify in advance)** The following explains how the reliability objective of the GOP and TOP coordinating changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of other TOPs. TPL-001-4 (*Transmission System Planning Performance Requirements*) Requirement R4 (Requirement R2 is inferred by reference) focuses on the Planning

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems. **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators	requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4. and 2.4.3. The Corrective Action Plan(s) shall: **IRO-002-4 (Approved)** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability	Assessment[33] performed by either the PC or the TP with aspects Protection Systems and RAS. Additionally, the projected Contingency conditions that are evaluated under TPL-001-4 by the PC and TP are considered by the TOP in performing an OPA. IRO-002-4 (*Reliability Coordination — Monitoring and Analysis*) Requirement R3 supports the inclusion of the Reliability Coordinator in Requirement R8 of PER-005-3. This function also has a responsibility to have knowledge of Protection Systems and RAS since it is

[33] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Planning Assessment is defined as a "[d]ocumented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **TOP-002-4 (Approved)** **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	monitoring Facilities, the status of SPSs, and non-BES facilities. TOP-002-4 (*Operations Planning*) The approved TOP-002-4, Requirement R1 that was developed since the Order was issued requires the TOP to have an OPA that will allow the TOP to assess whether its planned operations for the next day (i.e., "in advance") within its TOP Area will exceed any of its SOLs. The OPA requires inputs to assess anticipated (pre-Contingency[34]) and potential (post-Contingency) conditions for next-day operations. The TOP when performing its next-day planning through an OPA, will receive the necessary data "in advance" under TOP-003-3 and evaluate the projected system conditions to assess (using knowledge) anticipated pre-Contingency and potential post-Contingency conditions for

[34] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Contingency is defined as "[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems. **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	**TOP-003-3 (Approved)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	when generation, transmission, load, or operating conditions that could require changes in the other Transmission Operator's Protection Systems. By definition, an OPA evaluation shall reflect applicable inputs including Protection System and RAS status (change in status is implied) or degradation, but is not limited to: • load forecasts, • generation output levels, • Interchange, • known Protection System and Special Protection System status or degradation, • Transmission outages, • generator outages, • Facility Ratings, and • identified phase angle and equipment limitations.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	IRO-008-2 (Approved) **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.	IRO-008-2 (*Reliability Coordinator Operational Analyses and Real-time Assessments*) IRO-008-2, Requirement R2 requires each RC to have coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances. These exceedances are identified as a result of an OPA being performed in IRO-008-2, Requirement R1 while considering the Operating Plans for the next-day provided by each BA and TOP. Collectively, performing the OPA under TOP-002-4 using the necessary inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure), the Planning Assessment conducted under TPL-001-4, the jointly developed solutions under IRO-017-2, communication from the RC to the TOP under IRO-005-4, and the coordinated Operating Plan(s) under IRO-008-2 achieve the reliability objective of both PRC-001-

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	IRO-017-1 (Approved) **R3.** Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. **R4.** Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.	1.1(ii), Requirements R5.1 and R5.2 for "when changes in generation, transmission, load, or operating conditions could require changes in the other Transmission Operator's Protection Systems." IRO-017-1 (*Outage Coordination*) IRO-017-1, Requirement R3 requires each PC and TP to provide its Planning Assessment to an impacted RC. IRO-017-1, Requirement R4 requires each PC and TP to jointly develop solutions with each respective RC for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.[35]

[35] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Near-Term Transmission Planning Horizon is defined as "[t]he transmission planning period that covers Year One through five."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Requirement R6 is being proposed for retirement. The monitoring and notification in Requirement R6 is covered by: **IRO-002-4 (Approved)** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **TOP-001-3 (Approved)** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:	**PRC-001-1.1(ii), R6 (monitoring and notification of RAS)** IRO-002-4 (*Reliability Coordination — Monitoring and Analysis*) The reliability objective for the monitoring of RAS is addressed by IRO-002-4, Requirement R3 for the Reliability Coordinator TOP-001-3 (*Transmission Operations*) The reliability objective for the monitoring of RAS is addressed by TOP-001-3, Requirements R10 and R11 for the BA and TOP because they are required to monitor the status of a RAS.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	10.1. Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and **10.2.** Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency **TOP-003-3 (approved)** included by reference. See the section called, “shall notify.”	Notification of the change in status is addressed for the reasons explained under the “shall notify” sections above. In summary, the BA and TOP will receive notifications of inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure) from the applicable GOP and/or TOP under TOP-003-3 that was developed since the Order was issued.

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RELIABILITY CORPORATION

Evaluation of Proposed Definitions

Project 2007-06.2 – Phase 2 of System Protection Coordination

Introduction

The following definitions are proposed for revision under the Project 2007-06.2 – Phase 2 of System Protection Coordination. The definitions of "Operating Planning Analysis" (OPA) and "Real-time Assessment" (RTA) are used in the Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards.[1] To address the reliability objective PRC-001-1.1(ii) – Protection System Coordination, Requirement R1 to "be familiar with the purpose and limitations of Protection System schemes in its area," the two definitions are being modified to include the phrase "…functions, and limits…" to ensure the Transmission Operator (TOP), and Reliability Coordinator (RC) that is not applicable to PRC-001-1.1(ii), consider the functions and limits of Protection Systems and Remedial Action Schemes (RAS) in their OPA and RTA evaluations. Revising the definitions to require the RC and the TOP to integrate the functions and limits (i.e., purpose and limitations) into its OPA and RTA will ensure that the Bulk Electric System (BES) is operated within System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL).

Proposed Definitions

This section includes the Reliability Standards and the associated requirements where the two modified terms are found. These two terms are not found within the proposed PER-006-1 standard, but are an integral part of the basis for the retirement of PRC-001-1.1(ii), Requirement R1. There are two significant revisions, (1) an administrative update to replace "Special Protection System" to "Remedial Action Scheme" (RAS), and (2) the addition of the phrase "…functions, and limits…" to address the reliability objective of PRC-001-1.1(ii), Requirement R1 for the applicable TOP that must integrate the "functions and limits" into these evaluations. The proposed definition revision also has an effect on the Reliability Coordinator that is not applicable to PRC-001-1.1(ii). The bold text in the "Proposed Definitions" column accentuate the revisions.

[1] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order No. 817, 153 FERC ¶ 61,178 (2015).

Definitions (Effective January 1, 2017)	Proposed Definitions
Operational Planning Analysis An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)	**Operational Planning Analysis (OPA)** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to**:** load forecasts; generation output levels; Interchange; known Protection System and **Remedial Action Scheme** status or degradation**, functions, and limits**; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Real-time Assessment An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)	**Real-time Assessment (RTA)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load**;** generation output levels**;** known Protection System and **Remedial Action Scheme** status or degradation**, functions, and limits;** Transmission outages**;** generator outages**;** Interchange**;** Facility Ratings**;** and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Evaluation

The following is an evaluation of the potential impacts the modifications to the above definitions may have on the expected performance by the RC and TOP. The evaluation is limited to the Reliability Standards that will be or become in effect upon approval of the revised definitions.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-002-4 – Reliability Coordination – Monitoring and Analysis (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments.	The OPA definition revision has an impact on the RC in this requirement. The RC must include in its data exchange capability the “functions and limits” of Protection Systems and RAS needed to perform an OPA.
IRO-008-2 - Reliability Coordinator Operational Analyses and Real-time Assessments (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall perform an *Operational Planning Analysis* that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its *Operational Planning Analysis* as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.	**Requirement R1** The OPA definition revision has an impact on the RC in this requirement. The RC must integrate the “functions and limits” of Protection Systems and RAS in order to assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area. **Requirement R2** The OPA definition revision has no impact on the RC in this requirement. This requirement references that the results of the OPA are used by the RC to have a coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-010-2 – Reliability Coordinator Data Specification and Collection (Effective April 1, 2017) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.1.** A list of data and information needed by the Reliability Coordinator to support its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments.	**Requirement R1** The OPA definition revision has an impact on the RC in this requirement. The data needed by the RC regarding the "functions and limits" of Protection Systems and RAS to support performing an OPA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of OPA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2). **Requirement R2** The OPA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the OPA to others.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-014-3 - Coordination Among Reliability Coordinators (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1.** Criteria and processes for notifications. **1.2.** Energy and capacity shortages. **1.3.** Control of voltage, including the coordination of reactive resources. **1.4.** Exchange of information including planned and unplanned outage information to support its *Operational Planning Analyses* and Real-time Assessments. **1.5.** Provisions for periodic communications to support reliable operations.	The OPA definition revision has no impact on the RC in this requirement. Part 1.4 references that the RC must include information about planned and unplanned outages that support its OPA.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-002-4 – Operations Planning (Effective April 1, 2017) **R1.** Each Transmission Operator shall have an *Operational Planning Analysis* that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its *Operational Planning Analysis* as required in Requirement R1.	**Requirement R1** The OPA definition revision has an impact on the TOP in this requirement. The TOP must integrate the "functions and limits" of Protection Systems and RAS in order to assess whether its planned operations for the next day within its TOP Area will exceed any of its SOLs. **Requirement R2** The OPA definition revision has no impact on the TOP in this requirement. The TOP is using information resulting from its OPA.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-003-3 – Operational Reliability Data (Effective April 1, 2017) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.1.** A list of data and information needed by the Transmission Operator to support its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessment.	**Requirement R1** The OPA definition revision has an impact on the TOP in this requirement. The data needed by the TOP regarding the "functions and limits" of Protection Systems and RAS to support performing an OPA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of OPA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2.). **Requirement R2** The OPA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the OPA to others.

<table>
<tr><th colspan="2">Real-time Assessment (RTA)</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Description and Change Justification</th></tr>
<tr><td>IRO-002-4 – Reliability Coordination – Monitoring and Analysis (Effective April 1, 2017)
R1. Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.</td><td>The RTA definition revision has an impact on the RC in this requirement. The RC must include in its data exchange capability the “functions and limits” of Protection Systems and RAS needed to perform an RTA.</td></tr>
<tr><td>IRO-008-2 – Reliability Coordinator Operational Analyses and Real-time (Effective April 1, 2017)
R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
R5. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.</td><td>Requirement R4
The RTA definition revision has an impact on the RC in this requirement. The RC must include the “functions and limits” among other prescribed inputs from the definition of RTA.

Requirement R5
The RTA definition revision has no impact on the RC in this requirement. The RC is notifying others based on the results of its RTA that an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area.</td></tr>
</table>

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-009-2 - Reliability Coordinator Actions to Operate Within IROLs (Effective January 1, 2016) **R2.** Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or *Real-time Assessment*. **R3.** Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the Reliability Coordinator's Real-time monitoring or *Real-time Assessment*.	**Requirement R2** The RTA definition revision has no impact on the RC in this requirement. The RC will be taking an action to prevent an IROL exceedance, as identified in the RC's RTA. **Requirement R3** The RTA definition revision has no impact on the RC in this requirement. The RC will be acting or directing others so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the RC's RTA.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-010-2 – Reliability Coordinator Data Specification and Collection (Effective April 1, 2017) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*. The data specification shall include but not be limited to: **1.1.** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments* including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*.	**Requirement R1** The RTA definition revision has an impact on the RC in this requirement. The data needed by the RC regarding the "functions and limits" of Protection Systems and RAS to support performing an RTA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of RTA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2.). **Requirement R2** The RTA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the RTA to others.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-014-3 - Coordination Among Reliability Coordinators (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1.** Criteria and processes for notifications. **1.2.** Energy and capacity shortages. **1.3.** Control of voltage, including the coordination of reactive resources. **1.4.** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and *Real-time Assessments*. **1.5.** Provisions for periodic communications to support reliable operations.	The RTA definition revision has no impact on the RC in this requirement. Part 1.4 references that the RC must include information about planned and unplanned outages that support its RTA.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-001-3 – Transmission Operations (Effective April 1, 2017) **R13.** Each Transmission Operator shall ensure that a *Real-time Assessment* is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or *Real-time Assessment*.	**Requirement R13** The RTA definition revision has an impact on the TOP in this requirement. The TOP must include the "functions and limits" among the other prescribed inputs from the definition of RTA. **Requirement R14** The RTA definition revision has no impact on the TOP in this requirement. The TOP will be initiating its Operating Plan to mitigate a SOL exceedance identified in its RTA.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-003-3 – Operational Reliability Data (Effective April 1, 2017) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*. The data specification shall include, but not be limited to: **1.1.** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments* including non-BES data and external network data as deemed necessary by the Transmission Operator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and *Real-time Assessment*.	**Requirement R1** The RTA definition revision has an impact on the TOP in this requirement. The data needed by the TOP regarding the "functions and limits" of Protection Systems and RAS to support performing an RTA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of RTA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2.). **Requirement R2** The RTA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the RTA to others.

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Standards Announcement Reminder

Project 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 and Two Proposed Modified Definitions

Formal Comment Period Open through April 25, 2016

Now Available

Initial Ballots for **PER-006-1 – Specific Training for Personnel** and the **proposed modified definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA)** as well as a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern, Monday, April 25, 2016.**

Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard, definition, and associated VRFs and VSLs by clicking here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and determine the next steps of the project.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

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Standards Announcement

Project 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 and Two Proposed Modified Definitions

Formal Comment Period Open through April 25, 2016

Now Available

A 45-day formal comment period for **PER-006-1 – Specific Training for Personnel** and the **proposed modified definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA)** is open through **8 p.m. Eastern, Monday, April 25, 2016.**

Commenting

Use the electronic form to submit comments on the standard and definitions. If you experience any difficulties in using the electronic form, contact Wendy Muller**.** An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, April 8, 2016**. Registered Ballot Body members may join the ballot pools here.

Note: If you had previously joined the ballot pools for this project, you **must** join these new ballot pools to cast votes. Ballot pool members of the previous ballots for 2007-06.2 **will not** be carried over to these ballot pools.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. – 8 p.m. Eastern).

Next Steps

Initial ballots for the standard and the two definitions as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 15-25, 2016.**

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

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Standards Announcement

Project 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 and Two Proposed Modified Definitions

Formal Comment Period Open through April 25, 2016

Now Available

A 45-day formal comment period for **PER-006-1 – Specific Training for Personnel** and the **proposed modified definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA)** is open through **8 p.m. Eastern, Monday, April 25, 2016.**

Commenting

Use the electronic form to submit comments on the standard and definitions. If you experience any difficulties in using the electronic form, contact Wendy Muller**.** An unofficial Word version of the comment form is posted on the project page.

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If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. – 8 p.m. Eastern).

Next Steps

Initial ballots for the standard and the two definitions as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 15-25, 2016.**

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

Standards Announcement

Project 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 and Two Proposed Modified Definitions

Initial Ballot and Non-binding Poll Results

Now Available

A formal 45-day comment period and initial ballots for **PER-006-1 – Specific Training for Personnel** and the **proposed modified definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA),** as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded **8 p.m. Eastern, Monday, April 25, 2016.**

Voting statistics are listed below, and the Ballot Results page provides detailed results for the ballots and non-binding poll.

PER-006-1	Definitions of OPA and RTA	Non-binding Poll
Quorum / Approval	Quorum / Approval	Quorum / Supportive Opinions
83.39% / 80.57%	83.33% / 78.39%	80.43% / 71.43%

Next Steps
The drafting team will consider all comments received and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/46)
Ballot Name: 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 IN 1 ST
Voting Start Date: 4/15/2016 12:01:00 AM
Voting End Date: 4/25/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 251
Total Ballot Pool: 300
Quorum: 83.67
Weighted Segment Value: 80.57

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	78	1	43	0.729	16	0.271	0	7	12
Segment: 2	7	0.4	4	0.4	0	0	0	2	1
Segment: 3	63	1	37	0.74	13	0.26	0	4	9
Segment: 4	17	1	12	0.923	1	0.077	0	0	4
Segment: 5	78	1	41	0.707	17	0.293	0	2	18
Segment: 6	43	1	25	0.658	13	0.342	0	1	4
Segment: 7	3	0.2	2	0.2	0	0	0	1	0
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	2	0.2	2	0.2	0	0	0	0	0

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Segment: 10	6	0.4	4	0.4	0	0	0	2	0
Totals:	300	6.4	172	5.157	60	1.243	0	19	49

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Berkshire Hathaway	Terry Harbour		Affirmative	N/A

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	Energy - MidAmerican Energy Co.				
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Third-Party Comments
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	CPS Energy	Glenn Pressler		None	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A

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1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	William Smith		Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

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1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		None	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Negative	Third-Party Comments
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A

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1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Dawn Hamdorf	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	Third-Party Comments
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A

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2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Michael DeLoach		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		None	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A

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3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	KAMO Electric	Ted Hilmes		Affirmative	N/A

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	Cooperative				
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Chris Gowder	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Abstain	N/A

3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Jim Cox		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy	Kenneth Goldsmith		Affirmative	N/A

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	Corporation Services, Inc.				
4	Austin Energy	Tina Garvey		None	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila	Chris Gowder	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments

					Submitted
5	AES - AES Corporation	Leo Bernier		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		None	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Third-Party Comments

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5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Essential Power, LLC	Gerry Adamski		Affirmative	N/A
5	Exelon	Vince Catania		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		None	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric	Kayleigh Wilkerson		Affirmative	N/A

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	System				
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Wesley Maurer		None	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle	Scott Brame	Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail	Cathy Fogale		Affirmative	N/A

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	Power Company				
5	Oxy - Ingleside Cogeneration LP	Michelle D'Antuono		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Barbara Croas		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	Affirmative	N/A
5	SunPower	Bradley Collard		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		None	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted

5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Negative	Third-Party Comments
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Colorado Springs	Shannon Fair		Affirmative	N/A

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	Utilities				
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Exelon	Dave Carlson		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Third-Party Comments
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A

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6	Portland General Electric Co.	Adam Menendez		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		None	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Affirmative	N/A
7	Exxon Mobil	Jay Barnett		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A

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7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		None	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

Previous 1 Next

Showing 1 to 300 of 300 entries

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/46)
Ballot Name: 2007-06.2 Phase 2 of System Protection Coordination Modified Definitions of OPA and RTA IN 1 DEF
Voting Start Date: 4/15/2016 12:01:00 AM
Voting End Date: 4/25/2016 8:00:00 PM
Ballot Type: DEF
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 245
Total Ballot Pool: 293
Quorum: 83.62
Weighted Segment Value: 78.39

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	78	1	47	0.825	10	0.175	0	8	13
Segment: 2	6	0.4	0	0	4	0.4	0	1	1
Segment: 3	61	1	38	0.792	10	0.208	0	5	8
Segment: 4	16	1	11	0.917	1	0.083	0	1	3
Segment: 5	75	1	37	0.74	13	0.26	0	6	19
Segment: 6	43	1	26	0.722	10	0.278	0	4	3
Segment: 7	3	0.2	2	0.2	0	0	0	1	0
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	2	0.2	2	0.2	0	0	0	0	0

Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	293	6.5	170	5.095	48	1.405	0	27	48

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Berkshire Hathaway	Terry Harbour		Affirmative	N/A

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	Energy - MidAmerican Energy Co.				
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		None	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Third-Party Comments
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	CPS Energy	Glenn Pressler		None	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A

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1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Third-Party Comments
1	IDACORP - Idaho Power Company	Laura Nelson		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public	Jamison Cawley		Affirmative	N/A

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	Power District				
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		None	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Negative	Third-Party Comments
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A

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1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	Third-Party Comments
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A

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2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
3	AEP	Michael DeLoach		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		None	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative	Adam Weber		None	N/A

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	(Missouri)				
3	City of Leesburg	Chris Adkins	Chris Gowder	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Negative	Comments Submitted
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles	Mike Anctil		Affirmative	N/A

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	Department of Water and Power				
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Chris Gowder	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Abstain	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	Comments Submitted

3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Jim Cox		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		None	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila	Chris Gowder	Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal	Carol Chinn	Chris Gowder	Affirmative	N/A

	Power Agency				
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Abstain	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Leo Bernier		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		None	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A

5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Negative	Comments Submitted

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5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Essential Power, LLC	Gerry Adamski		Affirmative	N/A
5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		None	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Negative	Third-Party Comments
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Wesley Maurer		None	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A

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5	NB Power Corporation	Rob Vance		Negative	Third-Party Comments
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Negative	Third-Party Comments
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Oxy - Ingleside Cogeneration LP	Michelle D'Antuono		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Barbara Croas		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A

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5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Scotty Brown	Rob Collins	Negative	Comments Submitted
5	SunPower	Bradley Collard		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		None	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Negative	Third-Party Comments
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public	Bobbi Welch		Affirmative	N/A

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	Service Co.				
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Negative	Comments Submitted
6	City of Redding	Marvin Briggs	Bill Hughes	None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power	Ryan Streck		Affirmative	N/A

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	and Water				
6	New York Power Authority	Shivaz Chopra		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Third-Party Comments
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A

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6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Affirmative	N/A
7	Exxon Mobil	Jay Barnett		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		None	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

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Showing 1 to 293 of 293 entries

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/46)
Ballot Name: 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 Non-binding Poll IN 1 NB
Voting Start Date: 4/15/2016 12:01:00 AM
Voting End Date: 4/25/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 222
Total Ballot Pool: 275
Quorum: 80.73
Weighted Segment Value: 71.43

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	72	1	33	0.733	12	0.267	0	14	13
Segment: 2	6	0.2	1	0.1	1	0.1	0	3	1
Segment: 3	60	1	28	0.737	10	0.263	0	11	11
Segment: 4	15	1	9	0.9	1	0.1	0	2	3
Segment: 5	67	1	26	0.65	14	0.35	0	11	16
Segment: 6	41	1	17	0.586	12	0.414	0	4	8
Segment: 7	3	0.2	2	0.2	0	0	0	1	0
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	2	0.2	2	0.2	0	0	0	0	0

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Segment: 10	6	0.5	5	0.5	0	0	0	1	0
Totals:	275	6.3	125	4.806	50	1.494	0	47	53

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A

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1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	CPS Energy	Glenn Pressler		None	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	William Smith		Negative	Comments Submitted
1	Great Plains Energy -	James McBee	Douglas Webb	Negative	Comments

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	Kansas City Power and Light Co.				Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A

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1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Peak Reliability	Jared Shakespeare		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Negative	Comments Submitted
1	PPL Electric Utilities Corporation	Brenda Truhe		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric	Mark Churilla	Bret Galbraith	Affirmative	N/A

	Cooperative, Inc.				
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Negative	Comments Submitted
2	Southwest Power	Charles Yeung		None	N/A

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	Pool, Inc. (RTO)				
3	AEP	Michael DeLoach		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		None	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Leesburg	Chris Adkins	Chris Gowder	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A

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3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A

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3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Chris Gowder	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Jim Cox		None	N/A

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3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		None	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila	Chris Gowder	Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Chris Gowder	Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker	Chris Gowder	Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A

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4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Leo Bernier		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		None	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric	Shari Heino		None	N/A

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	Power Cooperative, Inc.				
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	Comments Submitted
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Exelon	Vince Catania		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		None	N/A

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5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Abstain	N/A
5	Lower Colorado River Authority	Wesley Maurer		None	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A

5	Oxy - Ingleside Cogeneration LP	Michelle D'Antuono		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Portland General Electric Co.	Barbara Croas		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Negative	Comments Submitted
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	SunPower	Bradley Collard		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		Negative	Comments Submitted

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5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	Westar Energy	stephanie johnson		Negative	Comments Submitted
6	AEP - AEP Marketing	Dan Ewing		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Exelon	Dave Carlson		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power	Chris Bridges	Douglas Webb	Negative	Comments Submitted

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	and Light Co.				
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Adam Menendez		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		None	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A

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6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	Scott Hoggatt		None	N/A
6	Westar Energy	Megan Wagner		Negative	Comments Submitted
7	Exxon Mobil	Jay Barnett		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		None	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel	Chris Gowder	Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A

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10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

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Showing 1 to 275 of 275 entries

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Comment Report

Project Name:	2007-06.2 Phase 2 of System Protection Coordination | PER-006-1 and Modified Definitions of OPA and RTA
Comment Period Start Date:	3/10/2016
Comment Period End Date:	4/25/2016
Associated Ballots:	2007-06.2 Phase 2 of System Protection Coordination Modified Definitions of OPA and RTA IN 1 DEF 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 IN 1 ST 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 Non-binding Poll IN 1 NB

There were 54 sets of responses, including comments from approximately 53 different people from approximately 51 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Generator Operator: Do you agree that the proposed PER-006-1 – Specific Training for Personnel appropriately replaces the responsibilities of the Generator Operator in PRC-001-1.1(ii) – System Protection Coordination, Requirement R1 (i.e., "…be familiar with the purpose and limitations of Protection Systems schemes…")? If not, please explain and provide suggestions to improve the PER-006-1 requirement.

2. Transmission Operator: The reliability objective of PRC-001-1.1(ii), Requirement R1 for the Transmission Operator (i.e., "…be familiar with the purpose and limitations of Protection Systems schemes…"), that is not already covered by the *Personnel Performance, Training, and Qualifications* (PER) Reliability Standards, is addressed by inserting the phrase "functions, and limits" into the proposed modified definitions of OPA and RTA. The Transmission Operator, by integrating the "functions and limits" of Protection Systems and Remedial Action Schemes into its OPA and RTA, will ensure that the Bulk Electric System is operated within System Operating Limits (SOL) and Interconnection System Operating Limits (IROL). Do you agree that the proposed modification of these terms as defined by the *Glossary of Terms Used in NERC Reliability Standards* achieves this reliability objective? If not, please explain and provide suggestions.

3. Reliability Coordinator: During the progression of Project 2007-06.2, it was determined that the Reliability Coordinator, a function that is not applicable to PRC-001-1.1(ii) should, similarly, "…be familiar with the purpose and limitations of Protection Systems schemes…" as found in Requirement R1 of the standard. The reliability objective for the Reliability Coordinator that is not already covered by the PER Reliability Standards, is being addressed by inserting the phrase "functions, and limits" into the proposed modified definitions of OPA and RTA. The Reliability Coordinator, by integrating the "functions and limits" of Protection Systems and Remedial Action Schemes into its OPA and RTA, will ensure that the Bulk Electric System is operated within SOL and IROL. Do you agree that the proposed modification of these terms as defined by the *Glossary of Terms Used in NERC Reliability Standards* achieves this reliability objective? If not, please explain and provide suggestions.

4. Do you agree with the proposed Violation Risk Factor (VRF) and Violation Severity Levels (VSLs) for the proposed PER-006-1 Requirement? If not, please provide a basis for revising the VRF and/or what would improve the clarity of the VSLs.

5. Do the PER-006-1, Application Guidelines provide sufficient guidance, basis for approach, and examples to support performance of the Requirement? If not, please provide specific detail that would improve the Application Guidelines.

6. Do you agree with implementation period (i.e., 12 months) of the proposed PER-006-1 Reliability Standard and the proposed definition modifications of OPA and RTA based on the considerations listed in the Implementation Plan? If not, please provide a justification for changing the proposed implementation periods.

7. Are you aware of any conflicts between the proposed PER-006-1 Reliability Standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If so, please identify the conflict here.

8. Are you aware of the need for a regional variance or business practice that should be considered with this project? If so, please identify it here.

9. If you have any other comments not previously mentioned above, please provide them here:

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Exelon	Chris Scanlon	1		Exelon Generation	Vince Catania	Exelon	5	RF
					Dave Carlson	Exelon	6	RF
Public Service Enterprise Group	Christy Koncz	1,3,5,6	NPCC,RF	PSEG	Tim Kucey	Public Service Enterprise Group	5	RF
					Karla Jara	Public Service Enterprise Group	6	RF
					Joseph Smith	Public Service Enterprise Group	1	RF
					Jeffrey Mueller	Public Service Enterprise Group	3	RF
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	MRO	3,4,5,6	MRO
					Chuck Lawrence	MRO	1	MRO
					Chuck Wicklund	MRO	1,3,5	MRO
					Dave Rudolph	MRO	1,3,5,6	MRO
					Kayleigh Wilkerson	MRO	1,3,5,6	MRO
					Jodi Jenson	MRO	1,6	MRO
					Larry Heckert	MRO	4	MRO
					Mahmood Safi	MRO	1,3,5,6	MRO
					Shannon Weaver	MRO	2	MRO
					Mike Brytowski	MRO	1,3,5,6	MRO

					Brad Perrett	MRO	1,5	MRO
					Scott Nickels	MRO	4	MRO
					Terry Harbour	MRO	1,3,5,6	MRO
					Tom Breene	MRO	3,4,5,6	MRO
					Tony Eddleman	MRO	1,3,5	MRO
					Amy Casucelli	MRO	1,3,5,6	MRO
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Southern Company - Southern Company Services, Inc.	3	SERC
					Bill Shultz	Southern Company - Southern Company Services, Inc.	5	SERC
					Jennifer Sykes	Southern Company - Southern Company Services, Inc.	6	SERC
Dominion - Dominion Resources, Inc.	Randi Heise	5		Dominion - RCS	Larry Nash	Dominion - Dominion Resources, Inc.	1	SERC
					Louis Slade	Dominion - Dominion Resources, Inc.	6	SERC
					Connie Lowe	Dominion - Dominion Resources, Inc.	3	RF
					Randi Heise	Dominion - Dominion Resources, Inc.	5	NPCC
California ISO	Richard Vine	2			Ali Miremadi	California ISO	2	WECC

				ISO/RTO Council Standards Review Committee	Greg Campoli	California ISO	2	NPCC
					Kathleen Goodman	California ISO	2	NPCC
					Nathan Bigbee	California ISO	2	Texas RE
					Terry Bilke	California ISO	2	MRO
					Ben Li	California ISO	2	NPCC
					Mark Holman	California ISO	2	RF
					Charles Yeung	California ISO	2	SPP RE
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC No NextEra	Paul Malozewski	Northeast Power Coordinating Council	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Brian Shanahan	Northeast Power Coordinating Council	1	NPCC
					Rob Vance	Northeast Power Coordinating Council	1	NPCC
					Mark J. Kenny	Northeast Power Coordinating Council	1	NPCC
					Gregory A. Campoli	Northeast Power Coordinating Council	2	NPCC
					Randy MacDonald	Northeast Power Coordinating Council	2	NPCC
					Wayne Sipperly	Northeast Power	4	NPCC

	Coordinating Council		
David Ramkalawan	Northeast Power Coordinating Council	4	NPCC
Glen Smith	Northeast Power Coordinating Council	4	NPCC
Brian Robinson	Northeast Power Coordinating Council	5	NPCC
Bruce Metruck	Northeast Power Coordinating Council	6	NPCC
Alan Adamson	Northeast Power Coordinating Council	7	NPCC
Michael Jones	Northeast Power Coordinating Council	3	NPCC
Michael Forte	Northeast Power Coordinating Council	1	NPCC
Kelly Silver	Northeast Power Coordinating Council	3	NPCC
Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
Edward Bedder	Northeast Power Coordinating Council	1	NPCC

					David Burke	Northeast Power Coordinating Council	3	NPCC
					Peter Yost	Northeast Power Coordinating Council	4	NPCC
					Helen Lainis	Northeast Power Coordinating Council	2	NPCC
					Michele Tondalo	Northeast Power Coordinating Council	1	NPCC
					Kathleen Goodman	Northeast Power Coordinating Council	2	NPCC
					Sylvain Clermont	Northeast Power Coordinating Council	1	NPCC
					Si Truc Phan	Northeast Power Coordinating Council	2	NPCC
					Sean Bodkin	Northeast Power Coordinating Council	4	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					Jason Smith	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					James Nail	Southwest Power Pool, Inc. (RTO)	3,5	SPP RE

					Michael Jacobs	Southwest Power Pool, Inc. (RTO)	NA - Not Applicable	NA - Not Applicable
					Mike Kidwell	Southwest Power Pool, Inc. (RTO)	1,3,5	SPP RE
					Robert Gray	Southwest Power Pool, Inc. (RTO)	NA - Not Applicable	NA - Not Applicable
					Stephanie Johnson	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP RE
					Bo Jones	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP RE
					Chris Dodd	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP RE
					J. Scott Williams	Southwest Power Pool, Inc. (RTO)	1,4	SPP RE
Oxy - Occidental Chemical	Venona Greaff	7		Oxy	Venona Greaff	Oxy - Occidental Chemical	7	SERC
					Michelle D'Antuono	Oxy - Occidental Chemical	5	Texas RE

1. Generator Operator: Do you agree that the proposed PER-006-1 – Specific Training for Personnel appropriately replaces the responsibilities of the Generator Operator in PRC-001-1.1(ii) – System Protection Coordination, Requirement R1 (i.e., "…be familiar with the purpose and limitations of Protection Systems schemes…")? If not, please explain and provide suggestions to improve the PER-006-1 requirement.	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	No
Document Name	
Comment	
It does not require the Generator Operator (GOP) to perform any verification activities of retention of the training following the training, nor does it address training refreshment. The results of this omission diverges from the structure established in PER-005-2 R1, R2, and R3, and would put the RE examiner in the position of testing all plant operators and assess their abilities to properly assign a VSL. It also follows that the RE examiner would have to be familiar with the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility. This could be a stretch for most examiners, and, at the very least, lengthen the time of preparation for examination.	
Likes 0	
Dislikes 0	
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5	
Answer	No
Document Name	
Comment	
M. LeRoy Patterson System Operator Trainer Grant County PUD (GCPD) Ephrata, WA Work: 509.754.7205 Mobile: 406.490.4254	

Internal ext: 4165

Email: Lpatterson@gcpud.org

- The notion that PRC-001 R1 required training of Plant Operators is not supported historically or by plain reading of that requirement. While some personnel within GOPs had to be trained (i.e. “familiar with”), the requirement is silent regarding specific GOP personnel requiring such training. Oddly, the drafting team recognizes this and uses such an interpretation as it recommends changes to assessment definitions to bring PRC-001 requirements under PER-005 for BAs, TOPs, RCs, etc.

- GCPD supports training in general and Plant Operator training specifically. Further, GCPD recognizes value in providing training to its employees, including Plant Operators.

That said, GCPD does not support PER-006 because there is no direct causal relationship between requiring training of Plant Operators and enhancing BES reliability benefits associated with Protection Systems and Remedial Action Schemes (RAS) other than the vague notion that training is always beneficial.

BES Reliability is affected adversely when Protection Systems and RAS are designed, implemented, and/or operated improperly. Of these three aspects, Plant Operators may have a role in their operation, but only from the standpoint of allowing such systems to be in service as directed or agreed upon by GOPs. For Protection Systems and RAS, which operate to protect equipment other than the unit being relayed offline, the GOP should be required to take agreed upon actions to place such systems in service and to keep such systems functional as long as the agreed upon conditions persist. This is the manner used to enforce having AVR and PSS in service.

For Protection Systems and RAS, which operate to protect the unit, GOPs have a stake in operating such systems appropriately. In addition, GOPs are required under existing requirements to coordinate regarding such systems with TOPs et al.

In both cases, it is likely GOPs provide training for Plant Operators to ensure proper operation of Protection Systems and RAS. However, mandating such training is specifying “how” to achieve an outcome rather than requiring a necessary performance. In both cases, requirements should be in place to operate such systems within design and implementation criteria because requiring training of Plant Operators will not achieve the desired result. In addition, training Plant Operators does nothing to ensure appropriate design and implementation of such protection systems, which presumably is included in remaining PRC requirements.

Hence, PER-006 does not accomplish an appropriate reliability objective. • If approved, PER-006 requires development of training materials, training classes, tracking systems, creation of evidence, and other administrative efforts to demonstrate compliance with PER-006. These extra tasks incur additional costs without a direct causal justification explaining why these additional costs contribute to the reliability of the BES as stated previously. • The reliability objective is better addressed by requiring protective systems be kept in service and functional much the same way as requirements for AVRs and PSSs.	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
See comments in question #5 AND at the end of these comments.	
Likes 0	
Dislikes 0	
Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	No
Document Name	
Comment	
The PSEG Companies agree that PER-006-1 appropriately addresses the responsibilities of the Generator Operator, however we are concerned that the phrase "*affect the output of the generating Facility(ies) it operates*" could be interpreted to require the Generator Operator to have knowledge of Protection Systems or RAS several substations distant from its point of interconnection. In this case, the Generator Operator could be required to understand the operational functionality of protection systems that the Generator Operator has no knowledge of. PSEG does not believe that this is the intent of the Standard Development Team, and suggests revising Requirement 1 to state**: "**Each Generator Operator shall provide training to personnel	

identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that are *associated with the generator interconnection* and affect the output of the generating Facility(ies) it operates."	
Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

Talen Energy respectfully requests that the "Note to Auditor" on p.4 of the draft RSAW be changed as follows:

Present text: "The documentation provided, including training if provided, should be specific to the operational functionality of Protection Systems and Remedial Action Schemes that affect output of the Facility. Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies). See Application Guidelines for details on what protective systems are covered. Generally, the Requirement focuses on those systems that are related to the electrical output of the generator."

Revised text: The documentation provided, including training if provided, need not be Facility-specific. If Facility-specific training is provided, however, it should be updated if necessary to address changes or additions to Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies). See Application Guidelines for details on what protective systems are covered. Generally, the Requirement focuses on those systems that are related to the electrical output of the generator.

Rationale: Changes or additions to Protection Systems or RASs would necessitate revisions to course materials and re-education of operators only if the training being given is Facility-specific, and PER-006-1 does not impose a requirement or even make a suggestion in this respect. The explanation of the term, "operational functionality," in the Guidelines and Technical Basis section of the standard does not include anything that would require training to be individualized for each plant, and the bullet points on p.9 of PER-006-list only topics of a general nature. The standard *permits* plant-specific training, but the Guidelines and Technical Basis material emphasizes the GOP's flexibility, which the RSAW as presently written seems to be taking away."

Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	
The adjustments as made extend the training to the Plant personnel which previously the training requirements were for the System Operators. This removes the training requirement from the Control Center Personnel who are more likely to need the understanding.	
Likes 0	
Dislikes 0	
Response	
Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	No
Document Name	
Comment	
The PSEG Companies agree that PER-006-1 appropriately addresses the responsibilities of the Generator Operator, however we are concerned that the phrase "*affect the output of the generating Facility(ies) it operates*" could be interpreted to require the Generator Operator to have knowledge of Protection Systems or RAS several substations distant from its point of interconnection. In this case, the Generator Operator could be required to understand the operational functionality of protection systems that the Generator Operator has no knowledge of. PSEG does not believe that this is the intent of the Standard Development Team, and suggests revising Requirement 1 to state**: "**Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that are *associated with the generator interconnection* and affect the output of the generating Facility(ies) it operates." PSEG, Segment(s) 5, 6, 1, 3, 3/10/2016	
Likes 0	
Dislikes 0	
Response	
Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	No
Document Name	
Comment	

Yes, however, FirstEnergy is voting NEGATIVE on the 1st Draft version due to concerns with text in the Guidance and Technical basis section of the standard. See question # 5 for more information.	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
See comments in question #5 AND question #9 at the end of these comments.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	No
Document Name	
Comment	

Kansas City Power and Light Company recommends withdrawal of PER-006-1 and its associated guideline, and offers an alternative to address GOP duties under proposed retired Standard PRC-001-1.1(ii). The recommendations are based on the following:

Generator Operator Not Equivalent to Plant Operators: PER-006-1 does not replace the responsibilities of the Generator Operator in PRC-001-1.1(ii). To replace one with the other would suggest parity between the two—an apple-to-apple change. Generator Operator in PRC-001-1.1(ii) applicability is at the entity level. The applicability under PER-006-1 is completely different, narrowly construed, creating a compliance duty on plant operators located at a generator's plant site and, as such, provides an apples-to-oranges change.

Generator Operator (GOP) is defined as, "The entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services [effective 07-01-2016]," referring to the responsibilities at the entity level. The Applicability for PER-006-1 establishes the compliance obligation at the operator—the individual person—level, with the effect of defining what a plant generator operator is and what an operator is not.

While establishing duties of system operators is not foreign in NERC Standard Requirements, in this particular case, we do not believe it is necessary.

GOP Already Responsible for Reliable Operation of Its System: The GOP and, in many situations, its delegates, carry a fundamental responsibility to supply energy in a manner that is not disruptive to the reliability of the Bulk Electric System (BES). If fulfilling that responsibility requires the GOP's lever-pullers, so to speak, at the generating plant to have awareness of Protection Systems and RAS, it is incumbent on the GOP to offer that awareness training whether a specific Standard exists or not. The GOP is in the best position to identify what training operators need to reliably manage their systems on the BES. This idea is reflected in soon to be enforceable, PER-005-2, Application Guidelines, Rationale for R6:

"The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods."

PER-005-2 applies to GOP control room operators, specifically excluding the generation facility operators. However, if the GOP, as the expert in its system and using a systematic method as provided in the guidelines, believes the generation facility operator needs to have awareness of Protection Systems and RAS, the GOP is going to extend awareness training to the generation facility operator because of the GOP's overarching duty to operate its system reliably with or without the onus of PRC-001-1.1(ii) or the proposed PER-006-1.

Every System is Unique: Remedial Action Schemes (RAS) are not applicable to all generators. Establishing a compliance duty under a Standard with a single Requirement to address a potential system design is inefficient and creates a challenge for entities that do not have relevant generator related RAS. In such a case, the entity has to prove a negative to show compliance; such an effort is often overly burdensome and, frankly, does little to promote reliability of the BES.

PER-005-2 Already Establishes GOP Training Responsibilities: To address the retirement of PRC-001-1.1(ii), we believe additional language to PER-005-2 Applicability 4.1.5.1 can effectively provide for the awareness training sought under proposed PER-006-1.

KCP&L suggests the following:

1. Withdraw PER-006-1 and its associated Guidelines.

2. Add language along the lines of the following as a bullet point following PER-005-2, Applicability 4.1.5.1:

- While the specific training set forth in this Standard is not applicable to plant operators located at a generator plant site, should the GOP determine there are systems or facilities that may impact the reliable operation of the Bulk Electric System (BES) and are relevant to the performance of plant operators' duties located at a generator plant site, the applicability may be extended to include plant operators at a generator plant site for the narrow purpose--to incorporate awareness training of specific systems or facilities that impact the BES. Such awareness training shall be incorporatedd into the GOP's systematic training methodology.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

We have several concerns that the intents of the drafting team haven't been accurately captured after participating in the Webinar (April 5, 2016). In reference to the term 'plant personnel', a drafting team member stated on the webinar that the "term wasn't just applicable to the operator but all staff and this supporting data could be found in the Technical Materials". We agree that this topic of discussion can be found in the Technical Materials section (Page 9- Guidelines: last two sentence of the first paragraph). There are examples provided to show what personnel shouldn't be included however, there are not examples reflecting who should be included. We suggest the drafting team include some clarifying examples of what type of 'plant personnel' should be included somewhere in the Technical Documentation. Our suggested example list would consist of (Operators, Engineers, Analysis……etc). We feel that type of information provides value as well.

Our second concern would be related to the Webinar (April 5, 2016) slides related to 'avoiding conflict with PER-005-2'.   It is our understanding that PER-005-2 Standard addresses personnel at a centrally located dispatch center while PER-006 addresses GOP (plant personnel). However, our concern comes from the Applicability section 4.1.5.1 (last sentence) of PER-005-2. The language mentions the personnel who wouldn't be covered under the PER-005-2. The other personnel mentioned are those at a "centrally located dispatch center who relay dispatch instructions without making any modifications". If PER-006-1 is to cover all 'plant personnel', but PER-005-2 is to cover some 'plant personnel' it seems there is either overlap or a gap that needs to be clarified. We suggest the drafting team re-evaluate the second set of 'plant personnel' mentioned in the section above and determine of more clarity can be provided as to which personnel should and should not be included.

Finally, our last concern is related to the required periodicity of training for the 'plant personnel'. The Standard (PER-006-1) nor its Technical Documentation states how often this training should be conducted. From the webinar information (April 5, 2016) it appears that the intent of the Drafting Team is that as the reliability needs change, the training should be re-performed in order to stay consistent with those changes. We feel that this intent is not being conveyed in the Standard or its supporting documentation. Without further clarification, our interpretation is that only **one** training session needs to be conducted to meet the reliability and compliance needs. Either additional language specifying training conducted in relation to changes to the RAS function, or a period of time that training should be conducted needs to be added. Our review group suggests the drafting team use similar language implemented into Requirement R6 of PER-005-2. That language requires training conducted each calendar year and is listed as follows:

"Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training".

Likes 0	
Dislikes 0	
Response	

Leo Bernier - AES - AES Corporation - 5	
Answer	No
Document Name	

Comment	
We believe the training on Radial Action Schemes is beyond the scope of the intent of the standard for a GOP.	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	

Comment	
The Bureau of Reclamation (Reclamation) supports PER-006-1 as an appropriate revision to the Generator Operator protection system training requirement in PRC-001-1 to address the reliability objective of operator familiarity with the “purpose and limitations of Protection Systems.” Reclamation believes that the proposed requirement includes meaningful clarification that training must address “the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of … generating Facility(ies).”	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Essential Power, LLC - 5	
Answer	Yes
Document Name	
Comment	
The main concern however is to contain the scope of "operational functionality" to that required to understand how the Protection System generally operates and affects the plant and not to necessarily require specific detailed knowledge of actual settings, etc. such that operators are expected to become system protection or relay experts.	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees that the proposed PER-006-1 appropriately covers the responsibilities of the Generator Operator in PRC-001-1.1(ii). However, we feel that the proposed PER-006-1 goes far beyond what is necessary to cover the responsibilities of the Generator Operator in PRC-001-1.1(ii) and protect the reliability of the Bulk Electric System. We feel that a basic understanding of and familiarity with protection systems and Remedial Action Schemes, as currently required, is adequate for promoting the reliability of the BES. Duke Energy does not believe that having generator specific training increases stability of the BES, and believes that the administrative effort, especially on larger utilities with numerous generating facilities, would be especially burdensome.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees the proposed PER-006-1 replaces the responsibilities of the Generator Operator in PRC-001-1.1(ii) (i.e., "…be familiar with the purpose and limitations of Protection Systems schemes…"). Texas RE suggest aligning the training with requirement with PER-005-2 R1.1.1 as to be done each calendar year. The Guidelines and Technical Basis document indicates that "[t]he structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service", but there is nothing indicating how often personnel should be trained.	
Likes 0	
Dislikes 0	
Response	

Ben Engelby - ACES Power Marketing - 6	
Answer	Yes
Document Name	
Comment	
We appreciate the SDT's efforts in developing this draft standard and thank the team for responding to our previous comments that recommended moving this requirement to the PER family of standards. We would like to point out that this standard is very specific with regard to the applicability section, and would hope that future standard projects do not attempt to consolidate other training standards and requirements to PER-006-1. There may be future unintended consequences if other training requirements were to be consolidated in this standard that is only applicable to a subset of plant personnel.	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	

John Fontenot - Bryan Texas Utilities - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rob Collins - Rob Collins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	Yes
Document Name	
Comment	
Likes 1	Oxy - Ingleside Cogeneration LP, 5, D'Antuono Michelle
Dislikes 0	
Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Generation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane	
Answer	
Document Name	
Comment	
N/A	

Likes 0	
Dislikes 0	
Response	

2. Transmission Operator: The reliability objective of PRC-001-1.1(ii), Requirement R1 for the Transmission Operator (i.e., "…be familiar with the purpose and limitations of Protection Systems schemes…"), that is not already covered by the *Personnel Performance, Training, and Qualifications* (PER) Reliability Standards, is addressed by inserting the phrase "functions, and limits" into the proposed modified definitions of OPA and RTA. The Transmission Operator, by integrating the "functions and limits" of Protection Systems and Remedial Action Schemes into its OPA and RTA, will ensure that the Bulk Electric System is operated within System Operating Limits (SOL) and Interconnection System Operating Limits (IROL). Do you agree that the proposed modification of these terms as defined by the *Glossary of Terms Used in NERC Reliability Standards* achieves this reliability objective? If not, please explain and provide suggestions.

Oshani Pathirane - Oshani Pathirane	
Answer	No
Document Name	
Comment	

While Hydro One Networks Inc. agrees that an evaluation may be performed for an OPA, an evaluation cannot be performed in real-time for an RTA. An OPA may be conducted over a longer period as next-day operations (as opposed to real-time operations) are considered. However, as the term implies, an RTA is conducted in real-time and therefore constitutes a quicker determination of conditions as opposed to a more time-consuming and comprehensive analysis. Therefore, Hydro One suggests that the definition of RTA start off with "*A determination of system conditions*…". The definition of OPA may be left as is if the definition of RTA is modified as suggested.

While Question #3 below pertains to the RC and does not pertain to Hydro One Networks Inc., Hydro One agrees with the NPCC that assurance that the BES is operated within SOLs and IROLs is separate from integrating the functions and limits of Protection Systems and Remedial Action Schemes into OPA an RTA. Further, Hydro One agrees with the NPCC that the term "limits" may imply SOLs and IROLs, which Protection Systems have little if not, any impact on. Therefore, the term "limitations" is a better substitute for the term "limits".

Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	

SRC does not agree with the modification of the OPA and RTA definitions. SRC believes that the existing PER standard covers the intended scope of PRC-001-1.1 and the change in the definitions of OPA and RTA goes beyond the original scope of PRC-001-1.1. Additionally, RCs have protection system and SPS knowledge and awareness requirements in the IRO standards.

However, if the SDT still believes the change in the definition of OPA and RTA is required, then there are better alternative phrases that will improve current proposal. The inclusion of the term “functions, and limits” in OPA and RTA can be misinterpreted. In the existing Glossary of Terms Used in NERC Reliability Standards (updated February 19, 2016) there are 21 references to “limit” or “Limit”, with vast majority of them referencing thermal, voltage, and stability limits and/or SOL and IROL.   SRC suggest SDT consider the following alternative phrases to "functions, and limits" that will eliminate future confusion: 1) operational functionality, 2) intended functions, and 3) functions and limitations.

Additionally, removing the word “schemes” from the phrase “protection system schemes” in translating this requirement from PRC-001-1.1 to the RTA and OPA definitions introduces confusion. Per the definition in the NERC Glossary of Terms, a protection system could be anything from a single protective relay to a set of relays designed to address a specific problem such as the exclusions identified in the RAS definition. The proposed language could be interpreted to mean that RCs/BAs/TOPs must be aware of the functions and limits of every single relay in its area, greatly expanding the scope of the requirements in the IRO and TOP standards that reference the RTA and OPA. SRC recommends the drafting team to use the defined term “Composite Protection System” instead of “Protection System”.

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE is concerned there is no explicit training requirement for TOPs and RCs on operational functionality of Protection Systems and Remedial Action Schemes (RAS).   PER-005-2 requires TOPs and RCs to develop a list of “reliability-related tasks” but it does not specify these tasks include Protection Systems and RASes. Texas RE is concerned that adding the terms “functions and limits” to the definitions do not ensure that each TOP will be familiar with the functions and limitations of its Protections Systems and RASes as they need to be in PRC-001-1.1(ii).

Additionally, with regard to the proposed definitions, SOL and IROL exceedances are only one aspect of situational awareness necessary for reliable operation of the BES. In order to maintain situational awareness, a TOP should be aware of Protection Systems and RASs to operate the system regardless of whether it is within SOLs or IROLs. For example, TOPs might be aware of how a unit tripped due to operation of a RAS and how that would impact an SOL or IROL exceedance. But you might not necessarily understand the reason of the generator trip as a result of the RAS operation and therefore lack knowledge of the duration of generator outage and other pertinent information.   The need for situational awareness beyond SOL and IROL exceedances is more important for the RC, as RCs are responsible for coordination among TOPs.

Likes 0	
Dislikes 0	

Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

As a best practice, ERCOT believes it is preferable to include requirements in the Reliability Standards rather than in definitions. Because requirements in definitions do not have associated measures or VRFs/VSLs, compliance and enforcement could be complicated.

ERCOT recognizes that the SDT's intent is to translate the requirement R1 of PRC-001-1.1 for the TOP and BA to "be familiar with the purpose and limitations of Protection System schemes applied in its area" to the RTA and OPA definitions used in the IRO/TOP standards. However, the change from the phrase "purpose and limitations of Protection System schemes" to the phrase "known Protection System and Remedial Action Scheme status or degradation, functions, and limits," is problematic for several reasons.

In the context of protection systems, SPSs, and RASs, the difference in meaning between "limits" and "limitations" is significant. The word "limits" in the proposed RTA and OPA definitions has the potential to be confused with system operating limits (SOLs). Requiring RCs and TOPs to consider SOLs for protection systems and RASs in RTAs and OPAs is unnecessary because GOs and TOs are already required to consider those SOLs for those facilities under FAC-008 R2.3 and R2.4.1 and FAC-008 R3.3 and R3.4.1. For this reason, ERCOT disagrees with Question 2's statement that the proposed definition changes "will ensure that the Bulk Electric System is operated within System Operating Limits (SOL) and Interconnection System Operating Limits (IROL)."

The word "limits" could also be misconstrued to mean limits on protection systems and RASs in the form of protection relay set points. Facility owners responsible for protection system maintenance and testing regularly collect and maintain relay set point information. However, this information has not been typically provided by facility owners to RCs and TOPs since Facility Ratings have been used to operate the system, and the set points for the majority of relays utilized to protect equipment are well beyond the Facility Ratings. Without guidance on which specific limit information is required, RCs and TOPs would potentially be required to consider an enormous number of relay set points, which are subject to constant change, making integration of this information into an RTA or OPA challenging and burdensome, without any meaningful reliability improvement. Furthermore, under the new IRO-008-2 Requirement R4, effective April 1, 2017, RCs are required to conduct an RTA every 30 minutes. Incorporating relay set point information into an RTA every 30 minutes means an RC would need to collect and incorporate large and constantly fluctuating data sets. This introduces a burdensome RC requirement without any discernible reliability benefit.

Introducing a “limit” to track under the RTA and OPA may also create confusion over the responsibility of the RC/TOP to respond to such a “limit” if reached or exceeded. If an RC/TOP is already operating to thermal limits, this additional limit is unnecessary and confusing. To avoid this confusion, ERCOT recommends the SDT replace the term “functions and limits,” with either (in order of preference): 1.) “operational functionality,” 2.) “intended functions,” or 3.) “functions and limitations.” ERCOT also recommends the SDT provide examples of how an RTA or OPA can be performed and documented to show evidence that “known Protection System and Remedial Action Scheme status or degradation and operational functionality” have been incorporated.

Additionally, removing the word “schemes” from the phrase “protection system schemes” in translating this requirement from PRC-001-1.1 to the RTA and OPA definitions introduces confusion. Per the definition in the NERC Glossary of Terms, a protection system could be anything from a single protective relay to a set of relays designed to address a specific problem such as the exclusions identified in the RAS definition. The proposed language could be interpreted to mean that RCs/BAs/TOPs must be aware of the functions and limits of every single relay in its area, greatly expanding the scope of the requirements in the IRO and TOP standards that reference the RTA and OPA. SRC recommends the drafting team to use the defined term “Composite Protection System” instead of “Protection System”.

ERCOT also recommends the SDT provide industry with guidance on distinguishing between “protection system schemes” and “protective relays” so as to avoid future confusion.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra

Answer	No
Document Name	

Comment

While we support the proposed revision to the two terms to achieve the intended purpose, we do not agree with the words “and limits”. The word “limits” lends itself to be interpreted as the system operating limits or interconnection system operating limits on which the Protection Systems, etc. have little bearing on. We suggest to reword the above to “functions and limitations” or “functions, limitations” to more accurately reflect the intent of the training on composite protection systems and RASs.

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
PER-005-2 requires a Systematic Approach to training for the Transmission Operator and Balancing Authority which includes the documented methodology of reliability related tasks addresses the PRC-001-1.1(ii) R1 requirement to "be familiar with the purpose and limitations of Protection System Schemes." The modification to these terms is NOT needed to achieve this reliability objective, since the training is already required as part of the PER-005 standard. Please explain how entities reading these definitions can relate that training on relays is needed by added the words "functions and limitations" to OPA and RTA.	
Likes 0	
Dislikes 0	
Response	
Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	No
Document Name	
Comment	
PSEG supports the PJM comments on this question.	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	No
Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Council- Standards Review Committee (SRC).	

Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	No
Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Council- Standards Review Committee (SRC).	
Likes 0	
Dislikes 0	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA supports PER-006-1 applicability solely to Generator Operators. However, BPA does not support the revised Operational Planning Analysis (OPA) and Real-Time Assessment (RTA) definitions as part of this project. BPA's concern is the compliance and reliability ambiguity presented by including "functions and limits" without specific guidance and/or requirements for the implementation of those terms. BPA desires to have the revised definitions excluded from project 2007-06.2. BPA suggests including the language in new or revised Standard(s) requirements, with specific guidance that would allow entities to meet the requirements and implementation of "functions and limits", such as TOP-001 and/or TOP-002.	
Likes 0	
Dislikes 0	
Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	No

Document Name	
Comment	
PSEG supports the PJM comments on this question.	
Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
Vectren supports a more clear use of “functions and limits” with respect to the transmission operators knowledge of Protection Systems. The transmission operators should have a clear understanding of the impacts of a Protections System on electrical facilities. Specifically, the operators should know and plan for the resulting state of facilities that would be outaged for a typical fault. Generally, most facilities will clear from breaker to breaker, but a SPS or RAS may energize or change state of other non-coincidental facilities. The transmission operator should know the “functions and limits” in the context of planning the extent of the outage. However, with the newer technology programmable relays, there are “function” statements inside of the relay that a system protection technician would know, but a transmission operator would not need to know. The same could be stated about limits. The programmable relays have many “limits” and timers inside the relay “functions” that the transmission operator does not need to know. Vectren agrees that limits, as it pertains to SOL’s and IROL’s, need to be used by the transmission operator. These limits are not in the same context as internal protection system “functions and limits” within a programmable relay.	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	No
Document Name	
Comment	

Vectren supports a more clear use of “functions and limits” with respect to the transmission operators knowledge of Protection Systems. The transmission operators should have a clear understanding of the impacts of a Protections System on electrical facilities. Specifically, the operators should know and plan for the resulting state of facilities that would be outaged for a typical fault. Generally, most facilities will clear from breaker to breaker, but a SPS or RAS may energize or change state of other non-coincidental facilities. The transmission operator should know the “functions and limits” in the context of planning the extent of the outage. However, with the newer technology programmable relays, there are “function” statements inside of the relay that a system protection technician would know, but a transmission operator would not need to know. The same could be stated about limits. The programmable relays have many “limits” and timers inside the relay “functions” that the transmission operator does not need to know. Vectren agrees that limits, as it pertains to SOL’s and IROL’s, need to be used by the transmission operator. These limits are not in the same context as internal protection system “functions and limits” within a programmable relay.

Likes 0	
Dislikes 0	

Response

Rob Collins - Rob Collins

Answer	No
Document Name	

Comment

Vectren supports a more clear use of “functions and limits” with respect to the transmission operators knowledge of Protection Systems. The transmission operators should have a clear understanding of the impacts of a Protections System on electrical facilities. Specifically, the operators should know and plan for the resulting state of facilities that would be outaged for a typical fault. Generally, most facilities will clear from breaker to breaker, but a SPS or RAS may energize or change state of other non-coincidental facilities. The transmission operator should know the “functions and limits” in the context of planning the extent of the outage. However, with the newer technology programmable relays, there are “function” statements inside of the relay that a system protection technician would know, but a transmission operator would not need to know. The same could be stated about limits. The programmable relays have many “limits” and timers inside the relay “functions” that the transmission operator does not need to know. Vectren agrees that limits, as it pertains to SOL’s and IROL’s, need to be used by the transmission operator. These limits are not in the same context as internal protection system “functions and limits” within a programmable relay.

Likes 0	
Dislikes 0	

Response

Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS

Answer	No
Document Name	

Comment	
Domminion supports the position of PJM and ISO-NE related to the proposed modification of these terms as defined by the *Glossary of Terms Used in NERC Reliability Standards*. While we support the proposed revision to the two terms to achieve the intended purpose, we do not agree with the words “and limits”. The word “limits” lends itself to be interpreted as the system operating limits or interconnection system operating limits on which the Protection Systems, etc. have little bearing on. We suggest to reword the above to “functions and limitations” or “functions, limitations” to more accurately reflect the intent of the training on composite protection systems and RASs.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
The proposal is to revise the RTA and OPA definitions to cover “RAS”, “functions” and “limits”. However, per these definitions a third party can perform the RTA and OPA for the TOP, and the BA is not even necessarily involved per future TOP standards. It is not clear that this proposal ensures the BA/TOP familiarity with Protection Systems related to “RAS”, “functions” and “limits”. Also, we have had an ongoing challenge determining who performs the GOP function; is it the folks at the “centrally located dispatch center” per PER-005-2 or is it the “plant personnel” per PER-006? Maybe in Functional Model these could be split into separate roles/registrations. Specific to PER-006, not requiring familiarity of Protection Systems for the GOP centrally located dispatch center folks may be a gap. NIPSCO presently complies with PRC-001-0 R1 with an approach that we believe will cover the requirement and revised definitions of Project 2007-06.2 Phase 2 and therefore is voting Affirmative, however we would like to see our concerns addressed. We appreciate the efforts of this SDT, especially the extensive outreach to stakeholders on this project.	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
While we support the proposed revision to the two terms to achieve the intended purpose, we do not agree with the words "and limits". The word "limits" lends itself to be interpreted as the system operating limits or interconnection system operating limits on which the Protection Systems, etc. have little bearing on. We suggest to reword the above to "functions and limitations" or "functions, limitations" to more accurately reflect the intent of the training on composite protection systems and RASs.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6	
Answer	Yes
Document Name	
Comment	
The proposed modification of these terms achieves the reliability objective.	
Likes 0	

Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

In our interpretation of the proposed changes to the definitions, the intent is that the TOP needs to be familiar with the 'functions and limits' of the Protection System and RAS so they can Identify and understand how those systems will impact system reliability and/or if that system reliability is reduced or threatened. Additionally, the operators must include this knowledge into their everyday process of analyzing and operating their portion of the system in reference to the (BES) SOL and IROL. Based on the presentations from the webinar (April 5, 2016), we interpret that the proposed changes are intended to ensure the Analysis Performance under PER-005-2 includes both the Protection System and RAS. If that is the case, we feel that the message may not be conveyed adequately in the mapping document. We suggest adding some footnotes or other language to the document stating why the Requirements are mentioned, however we're not sure that the end goal is sufficiently communicated in order to help the industry understand the proposed changes.

Additionally we suggest the drafting team consider whether the proposed changes to the definitions should be conducted independent of this project. There are already many moving pieces in this project and this only adds more confusion. Technically, there are five proposed Standards associated with this project and all depends on the retirement of PRC-001 and its Requirements. Adding two definitions from the previous TOP/IRO Project warrants its own attention.

Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	Yes
Document Name	
Comment	

No comments.

Likes 0	

Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC supports the proposed revisions because NERC’s explanation matches ATC's expectation regarding the correct understanding of the new, undefined terms “functions” and “limits”. For example, ATC correlates “functions” with “purpose” of Protection Systems and Remedial Action Schemes, which would mean understanding that there are different functions implemented by relaying such as undervoltage protection, overcurrent protection, impedance relaying, etc. Additionally, ATC understands “limits” to correlate with current PRC-001-1.1(ii) term “limitations”, which would mean understanding the limitations of relaying such as overspeed generator protection will not clear a fault by design, a bus differential will not clear a fault outside of its zone of protection, pulling relay trips means a breaker won’t trip if the relay sends a signal to trip, etc. This corresponds to ATC's understanding that "limits" does **not** refer to defining System Operating Limits due to relay settings, in cases where the relay setting produces a lower facility rating than the other connected equipment, because facility limits due to relay settings (or other equipment) are covered by NERC Standard FAC-008-3 R3.4.1 and the NERC Glossary of Terms definition for "System Operating Limit".	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	
Document Name	
Comment	
N/A	
Likes 0	

Dislikes 0	
Response	

3. Reliability Coordinator: During the progression of Project 2007-06.2, it was determined that the Reliability Coordinator, a function that is not applicable to PRC-001-1.1(ii) should, similarly, "…be familiar with the purpose and limitations of Protection Systems schemes…" as found in Requirement R1 of the standard. The reliability objective for the Reliability Coordinator that is not already covered by the PER Reliability Standards, is being addressed by inserting the phrase "functions, and limits" into the proposed modified definitions of OPA and RTA. The Reliability Coordinator, by integrating the "functions and limits" of Protection Systems and Remedial Action Schemes into its OPA and RTA, will ensure that the Bulk Electric System is operated within SOL and IROL. Do you agree that the proposed modification of these terms as defined by the *Glossary of Terms Used in NERC Reliability Standards* achieves this reliability objective? If not, please explain and provide suggestions.

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

Same comment as in Q2, above.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

I don't think RCs will ever be familiar with the purpose and limitations of PS schemes in their footprint; it is too vast an area. However this is not a "show stopper" for us since we are not an RC.

Likes 0	
Dislikes 0	

Response

Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS

Answer	No
Document Name	
Comment	

Dominion supports PJM on the following comment:

PJM agrees with the intention of the drafting team but believes there are better alternative phrases that will improve current proposal. The inclusion of the term “functions, and limits” in Operational Planning Analysis (OPA) and Real-time Assessment (RTA) can be misinterpreted. In the existing Glossary of Terms Used in NERC Reliability Standards (updated February 19, 2016) there are 21 references to “limit” or “Limit”, with vast majority of them referencing thermal, voltage, and stability limits and/or SOL and IROL.   SRC suggest SDT consider the following alternative phrases to "functions, and limits" that will eliminate future confusion: 1) operational functionality, 2) intended functions, and 3) functions and limitations.

Likes 0	
Dislikes 0	
Response	

Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG

Answer	No
Document Name	
Comment	

PSEG supports the PJM comments on this question

Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	

William Temple - William Temple

Answer	No
Document Name	
Comment	

PJM supports the comments submitted by the ISO/RTO Council- Standards Review Committee (SRC).

Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	No
Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Council- Standards Review Committee (SRC).	
Likes 0	
Dislikes 0	
Response	
Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	No
Document Name	
Comment	
PSEG supports the PJM comments on this question.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	No
Document Name	
Comment	

While we support the proposed revision to the two terms to achieve the intended purpose, we do not agree with the words “and limits”. The word “limits” lends itself to be interpreted as the system operating limits or interconnection system operating limits on which the Protection Systems, etc. have little bearing on. We suggest to reword the above to “functions and limitations” or “functions, limitations” to more accurately reflect the intent of the training on composite protection systems and RASs.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

Comments: Please see response to question 2.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE is concerned there is no explicit training requirement for and RCs on operational functionality of Protection Systems and Remedial Action Schemes (RAS). PER-005-2 requires TOPs and RCs to develop a list of “reliability-related tasks” but it does not specify these tasks include Protection Systems and RASes.

Additionally, with regard to the proposed definitions, SOL and IROL exceedances are only one aspect of situational awareness necessary for reliable operation of the BES. In order to maintain situational awareness, the RC should be aware of Protection Systems and RASs to operate the system regardless of whether it is within SOLs or IROLs. For example, the RC might be aware of how a unit tripped due to operation of a RAS and how that would impact an SOL or IROL exceedance. But you might not necessarily understand the reason of the generator trip as a result of the RAS operation

and therefore lack knowledge of the duration of generator outage and other pertinent information. The need for situational awareness beyond SOL and IROL exceedances is more important for the RC, as RCs are responsible for coordination among TOPs.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
Please see response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes

Document Name	
Comment	

In our interpretation of the proposed changes to the definitions, the intent is that the RC needs to be familiar with the 'functions and limits' of the Protection System and RAS so they can Identify and understand how those systems will impact system reliability and/or if that system reliability is reduced or threatened. Additionally, the operators must include this knowledge into their everyday process of analyzing and operating their portion of the system in reference to the (BES) SOL and IROL. Based on the presentations from the webinar (April 5, 2016), we interpret that the proposed changes are intended to ensure the Analysis Performance under PER-005-2 includes both the Protection System and RAS. If that is the case, we feel that the message may not be conveyed adequately in the mapping document. We suggest adding some footnotes or other language to the document stating why the Requirements are mentioned, however we're not sure that the end goal is sufficiently communicated in order to help the industry understand the proposed changes.

Additionally we suggest the drafting team consider whether the proposed changes to the definitions should be conducted independent of this project. There are already many moving pieces in this project and this only adds more confusion. Technically, there are five proposed Standards associated with this project and all depends on the retirement of PRC-001 and its Requirements. Adding two definitions from the previous TOP/IRO Project warrants its own attention.

Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6	
Answer	Yes
Document Name	
Comment	

The proposed modification of these terms achieves the reliability objective.

Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Leo Bernier - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	

Rob Collins - Rob Collins	
Answer	
Document Name	
Comment	
Vectren is not registered as a Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	
Document Name	
Comment	
n/a	
Likes 0	

Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the proposed Violation Risk Factor (VRF) and Violation Severity Levels (VSLs) for the proposed PER-006-1 Requirement? If not, please provide a basis for revising the VRF and/or what would improve the clarity of the VSLs.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy does not believe that a VRF rating of Medium is appropriate for this requirement. We feel that a VRF of Low is more suitable based on the risk that the requirement poses to the BES.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	No
Document Name	
Comment	
Kansas City Power and Light Company recommends withdrawal of PER-006-1, making the VRF and VSL moot.	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	No
Document Name	
Comment	

Violation Severity Levels (VSL) are based on the number of applicable personnel that the GOp failed to train. While TVA understands that NERC and the SDT assigns more risk to non-compliance to these training requirements than was represented in PRC-001-1.1b, TVA believes the drafted thresholds escalate too aggressively. Also, the VSL for failing to train 4 individuals at a single site should be explicit. Given that the greater of the two thresholds for each VSL will apply to any non-compliance, TVA suggests changes to the drafted thresholds as follows.

- **Lower VSL**: (no change).
- **Moderate VSL**: 2 applicable personnel at a single site; or more than 5% and less than 15% of the total applicable personnel of the GOp.
- **High VSL**: 3 or 4 applicable personnel at a single site; or more than 15% and less than 25% of the total applicable personnel of the GOp.
- **Severe VSL**: 5 or more applicable personnel at a single site; or more than 25% of the total applicable personnel of the GOp.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1, Group Name Exelon Generation

Answer	No
Document Name	

Comment

Violation Risk Factor

The Violation Risk Factor (VRF) of Medium related to a failure to provide evidence of training for plant operators does not seem to meet the criteria for a Medium Risk factor unless the lack of that training causes an event to occur. A Medium Risk factor is defined as follows:

"A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. "

It would seem more appropriate for this to be considered a Low Risk factor as a lack of being able to provide evidence of training is administrative and is defined as:

"A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature."

Violation Severity Level	
The Violation Severity Levels (VSLs) should be enhanced to be explicit in the minimum elements of the training. If an entity provided any training at all it is conceivable that training (regardless of content) would be considered compliant. Exelon does not believe that is the intent of the SDT. Consider revising the technical basis to provide the minimum expectations for the content of the training and revising the VSL to be more specific to the lack of the training containing those elements.	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Amy Casuscelli	
Answer	No
Document Name	
Comment	
The VSL for missing one operator at a facility with a large staff might mean missing less than 5% of the operators while at a small peaking or black start unit missing one operator could be 50% to 100% of the people at the site. We propose that he VSL would make more sense if the criteria for a single facility was a percentage of operators at that site missing training, rather than the number of personnel missing the training.	
Likes 0	
Dislikes 0	
Response	

Angela Gaines - Portland General Electric Co. - 3	
Answer	No
Document Name	
Comment	
Although PGE appreciates the flexibility that the Standard Drafting Team wrote into this standard, it is difficult to measure compliance as it is written. The current version of PER-006 does not indicate how the VSL will be used to measure compliance beyond the initial training specified by the implementation plan.	
Likes 0	

Dislikes 0	
Response	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	No
Document Name	
Comment	
It does not require the Generator Operator (GOP) to perform any verification activities of retention of the training following the training, nor does it address training refreshment. The results of this omission diverges from the structure established in PER-005-2 R1, R2, and R3, and would put the RE examiner in the position of testing all plant operators and assess their abilities to properly assign a VSL. It also follows that the RE examiner would have to be familiar with the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility. This could be a stretch for most examiners, and, at the very least, lengthen the time of preparation for examination.	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Essential Power, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rob Collins - Rob Collins	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

5. Do the PER-006-1, Application Guidelines provide sufficient guidance, basis for approach, and examples to support performance of the Requirement? If not, please provide specific detail that would improve the Application Guidelines.

Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	No
Document Name	
Comment	
It does not require the Generator Operator (GOP) to perform any verification activities of retention of the training following the training, nor does it address training refreshment. The results of this omission diverges from the structure established in PER-005-2 R1, R2, and R3, and would put the RE examiner in the position of testing all plant operators and assess their abilities to properly assign a VSL. It also follows that the RE examiner would have to be familiar with the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility. This could be a stretch for most examiners, and, at the very least, lengthen the time of preparation for examination.	
Likes 0	
Dislikes 0	
Response	

Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	

Guidance and Technical Basis Section R1:

- “plant personnel” and “GOP” are used interchangeably throughout this Guidance and Technical Basis section. As identified on the commenting sessions with the drafting team, the drafting team identified that the control function may occur in various “entity configurations”. Example given was that a central GOP dispatch center may be the function that controls the generator and not the plant itself. Suggest you change the use of "plant" to "GOP" and/or provide a qualifier for understanding.
- Paragraph 1: Sentence 2 that reads “To accomplish this, **plant personnel responsible for Real-time control and operation of a generating Facility** must understand how Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility". Remove **“and operation”,** as this causes confusion as to whom is to be trained. Explanations during commmenting sessions was very confusing on whom this Standard applies. We do understand that there are different functional applications through the utility industry, however it would seem that the use of “Real-time” [a NERC defined term] indeed makes it clear that it is the “first responders” (first responders, a term used by the SDT in clarifying their position on this Standard). Note: remove “and operation” in subsequent paragraphs also.

- Paragraph 1, sentence 2 that reads: "To accomplish this, plant personnel responsible for Real-time control and operation of a generating Facility **must understand** how Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility." Delete **“must understand”** and insert **“must be trained on**”. There is no testing associated with this Standard, only training. “must understand” implies a testing measurement function. This change lines up with the Requirment 1.

- Paragraph 2. Sentence that states "A periodicity for training is not specified in Requirement R1 because it is incumbent upon the GOP to ensure its plant personnel that have Real-time control and operation of a generator are trained in order to operate the plant" . You are correct a periodocity is not specified and is also not a part of the Standard. The Requirement and its mesurement do not even imply retraining. Only the Guidance and Technical Basis and the RSAW address re-training. Please see the proposed addition in #1 of the ‘Additional Comments’ at the end of the commenting form for proposed addition to the Requirement 1. In addition the RSAW, in the ‘Evidence Requested” section asks the auditor to verify documentation of changes or additions or Protection Systems and RAS during the compliance monitoring period (this RSAW requirement comes from language in the Guidelines and Technical Basis section). This is not called out in the Standard and should be added to the R1- Mesurements or elsewhere in the Requirment.

- Paragraph 2, Second sentence that states “The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service". Delete this sentence as training frequency is already covered in the sentence following the proposed deleted sentence. The two sentences contradict each other.

- Paragraph 2 Sentence that states “On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS". The RSAW ‘Note to Auditor’ section is explicit that Training should be updated for additions and changes. This does not meet the intent of the SDT (as noted in the sentence identified above "the GOP has the flexibility…"). As written this will lead to different audit practices throughout the industry. If the training is not updated, as the current RSAW language is written, this could be a violation in audit application. See #2 of the ‘Additional Comments’ section at the bottom of this commenting form for proposed RSAW change and in addition the already provided #1 in the ‘Additional Comments’ section below.

Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	

Recommend the addition within Guidance and Technical Basis to align with the Section 4.1 of this Standard:

Requirement R1

The Generator Operator (GOP) monitors and controls its generating Facilities in Real-time to maintain reliability. To accomplish this, applicable plant personnel responsible for Real-time control and operation of a generating Facility must understand how Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility.

Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The Application Guidelines should be revised to preclude the RSAW conflict discussed above, i.e. directly stating that Facility-specific course materials are not obligatory.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Generation	
Answer	No
Document Name	
Comment	

Exelon requests that the SDT be more specific regarding the applicable systems that would fall within the scope of PER-006-1. The current draft provides an exclusion for those protective systems which trip breakers serving station auxiliary loads, secondary unit substations or low switchgear transformers and relays protecting other downstream plant electrical distribution system components (even if a trip of these devices might result in a trip of the unit); however it, does not address the following:

1. Protection systems associated with station auxiliary transformers that supply the station and are fed by external power IF the protection system would open breakers that affect the Bulk Electric System (BES) (e.g., the breakers feed into a ring bus). [Note this does not include a transformer fed from a radial line]. Trip of these transformers may or may not trip the unit depending on the plant design.

2. Protection systems associated with unit auxiliary transformers that supply the station and are fed by the generating unit. In this case the trip of the auxiliary transformer would directly trip the generating unit.

Furthermore, the considerations for operational functionality should list the minimum training elements required – not provide the latitude for an auditor or entity to interpret what should be considered.

Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	No
Document Name	
Comment	

No "Application Guidelines" were found in the standard. This answer is based on the assumption that the question intended to reference the " Guidelines and Technical Basis."

The second sentence of the second paragraph of the Guidelines and Technical Basis states,

“The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service.”

While the interpretation provided here is appreciated, TVA does not agree with the premise of the statement. If the intention of the SDT is to require GOP personnel receive training before a Protection System or RAS is placed into service, then R1 or a sub-requirement should state this explicitly, which would comport with maintaining Reliability of the BES.

Further, the next sentence states,

"On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e .g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS."

The “flexibility” given the GOP in this sentence “concerning new systems” is inconsistent with the previous sentence and creates ambiguity regarding when training for new systems is required. The phrase “ongoing basis” would imply the statement is addressing training after a Protection System or RAS has been placed into service, but the parenthetical “concerning new systems” creates the inconsistency.

Likes 0	
Dislikes 0	
Response	

Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	

Guidance and Technical Basis Section R1:

- “plant personnel” and “GOP” are used interchangeably throughout this Guidance and Technical Basis section. As identified on the commenting sessions with the drafting team, the drafting team identified that the control function may occur in various “entity configurations”. Example given was that a central GOP dispatch center may be the function that controls the generator and not the plant itself. Suggest you change the use of "plant" to "GOP" and/or provide a qualifier for understanding.

- Paragraph 1: Sentence 2 that reads “To accomplish this, **plant personnel responsible for Real-time control and operation of a generating Facility** must understand how Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility". Remove **“and operation”,** as this causes confusion as to whom is to be trained. Explanations during commmenting sessions was very confusing on whom this Standard applies. We do understand that there are different functional applications through the utility industry, however it would seem that the use of “Real-time” [a NERC defined term] indeed makes it clear that it is the “first responders” (first responders, a term used by the SDT in clarifying their position on this Standard). Note: remove “and operation” in subsequent paragraphs also.

- Paragraph 1, sentence 2 that reads: "To accomplish this, plant personnel responsible for Real-time control and operation of a generating Facility **must understand** how Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility." Delete **“must understand”** and insert **“must be trained on**”. There is no testing associated with this Standard, only training. “must understand” implies a testing measurement function. This change lines up with the Requirment 1.

- Paragraph 2. Sentence that states "A periodicity for training is not specified in Requirement R1 because it is incumbent upon the GOP to ensure its plant personnel that have Real-time control and operation of a generator are trained in order to operate the plant" . You are correct a periodocity is not specified and is also not a part of the Standard. The Requirement and its mesurement do not even imply retraining. Only the Guidance and Technical Basis and the RSAW address re-training. Please see the proposed addition in #1 of the ‘Additional Comments’ at the end of the commenting form for proposed addition to the Requirement 1. In addition the RSAW, in the ‘Evidence Requested” section asks the auditor to verify documentation of changes or additions or Protection Systems and RAS during the compliance monitoring period (this RSAW requirement comes from language in the Guidelines and Technical Basis section). This is not called out in the Standard and should be added to the R1- Mesurements or elsewhere in the Requirment.

- Paragraph 2, Second sentence that states “The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service". Delete this sentence as training frequency is already covered in the sentence following the proposed deleted sentence. The two sentences contradict each other.

- Paragraph 2 Sentence that states “On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS". The RSAW ‘Note to Auditor’ section is explicit that Training should be updated for additions and changes. This does not meet the intent of the SDT (as noted in the sentence identified above "the GOP has the flexibility…"). As written this will lead to different audit practices throughout the industry. If the training is not updated, as the current RSAW language is written, this could be a

violation in audit application. See #2 of the 'Additional Comments' section at the bottom of this commenting form for proposed RSAW change and in addition the already provided #1 in the 'Additional Comments' section below.	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
The application guidelines lack a true description of who the standard applies to. The NERC Functional Model defines Generator Operator as: "The functional entity that operates generating unit(s) and performs the functions of supplying energy and reliability related services." Question arises does this apply only to registered entities of the "Generator Operator" regardless of their voltage level, generation capacity and point of interconnection with the BES?	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb	
Answer	No
Document Name	
Comment	
Kansas City Power and Light Company recommends withdrawal of PER-006-1 and its associated guidelines, making the Application Guidelines moot.	
Likes 0	
Dislikes 0	
Response	

Ben Engelby - ACES Power Marketing - 6	
Answer	No
Document Name	
Comment	
We recommend that the drafting team clarify in the Application Guidelines for Requirement R1 that one-time training is required for applicable plant personnel. There is nothing in the language of the requirement to require additional, continuing, and/or retraining to occur. The RSAW has made an assumption that retraining is required, which needs to be corrected to align with the requirement. If the SDT does intend for additional, continuing and/or retraining, this would be a substantive change and would require another posting of the revised requirement for industry comment and ballot.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	Yes
Document Name	PER_006_1_System_Protection_Draft_1_FE Comments.docx
Comment	

FirstEnergy Comments

PER-006-1 – Specific Training for Personnel

Draft 1 – Ballot Ending April 25, 2016

The following comments are offered to the NERC Standard Draft Team (SDT) to support why FirstEnergy (FE) has voted NEGATIVE on the 1st Draft version of PER-006-1. Our comments also offered suggested revisions in order for FE to support the standard.

1. The 2nd paragraph of the Guidelines and Technical Basis section includes the statement *"The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service."* FE recommends the text be deleted as it is inconsistent with the R1 requirement as presented in Draft 1. This statement adds additional obligations not within the standard. Nowhere in the requirement language is this "dictated" or required. Additionally, this could raise questions to when training is needed for revised Protection Systems that may only include minor setting changes for coordination improvement but no material change in the intended outcome of the protection scheme.

2. The Guidelines and Technical Basis section offers 6 bullet listed items/topics for consideration for training intended to cover the "operational functionality" of a Protection System or RAS. FE offers a re-write of this area to place greater emphasis on the first and last bulleted items which we believe are the most appropriate areas to cover with generation plant operators. The other four items are more technical and design/engineering details that should be more clearly optional.

3. As a minor note, FE suggests adding the word "Operations" in the standard title to read "Specific Training for Operations Personnel". Doing so would better compliment the PER-005-2 standard which is titled "Operations Personnel Training" which focuses on a systematic approach to training for reliability related tasks.

The attached file includes an excerpt of the Draft 1 PER-006-1 standard with suggested red-line edits to the Guidelines and Technical Basis section.

If the SDT wishes to discuss FE's comments please contact Doug Hohlbaugh, Manager, Reliability Compliance at 330-384-4698.

Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rob Collins - Rob Collins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	Yes
Document Name	
Comment	
Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Essential Power, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

6. Do you agree with implementation period (i.e., 12 months) of the proposed PER-006-1 Reliability Standard and the proposed definition modifications of OPA and RTA based on the considerations listed in the Implementation Plan? If not, please provide a justification for changing the proposed implementation periods.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy does not believe that an Implementation Plan of 12 months is appropriate for the amount of work that would be involved for larger utilities with numerous generating facilities. An entity would need time to develop additional training materials (in addition to what is already in use for compliance with PRC-001-1.1(ii)) with specificity for each of its generating facilities, and then administer said training to all applicable operators within a 12 month timeframe. A significant amount of time would need to be allotted to accomplish develop and distribute the additional required tasks, much more than the proposed 12 months.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Comments: As currently worded, the modification of OPA and RTA may require entities to collect and include a large, voluminous set of data in their RTAs and OPAs. This would require entities to make modeling and Energy Management System changes to accommodate all the relay information, which would require time to upgrade technology. Taking into account budgeting, design, and implementation, the time necessary to upgrade this technology could run 24 to 36 months.	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	

Answer	No
Document Name	
Comment	

A period of 12 months is too short to generate operator lists, identify the "Set of Protection Systems and Remedial Action Schemes" and to create and roll out a new training program. Suggest at least a 24 month period.

Likes 0	
Dislikes 0	
Response	

Tim Kucey - PSEG - PSEG Fossil LLC - 5

Answer	No
Document Name	
Comment	

PSEG thanks the drafting team for its efforts and appreciates having the opportunity to comment on the proposed OPA and RTA definitions. PSEG is in general agreement with the intent of the proposed OPA and RTA definitions as it applies to the inclusion of Protection Systems and RASs in evaluations and assessments (that would be conducted by operations personnel). The wording of the current version of each definition states that OPA evaluations and RTA assessments "…shall reflect applicable inputs including… known Protection System and Remedial Action Scheme status or degradation, functions, and limits…". PSEG agrees that OPAs and RTAs should include the status or degradation of known protection systems and RASs. Additionally, we believe that inclusion of the "functions and limits" of RASs in OPAs and RTAs would improve reliability. However, it is requested that the requirement to include the "functions and limits" of [all] known Protection Systems be removed from the OPA and RTA definitions. As they are currently written, the definitions imply that the (operations) personnel who perform OPAs and RTAs would require detailed information regarding the settings for all protection systems (or schemes) that are within their scope of operations in order to complete OPAs and RTAs. PSEG does not believe that this level of detail regarding [all] protection systems is necessary in OPAs and RTAs in order to maintain reliability of the BES. PSEG therefore proposes that the definitions be revised as follows:

Operational Planning Analysis (OPA)

An evaluation of projected system conditions to assess anticipated (pre Contingency) and for next -day operations. The evaluation shall reflect applicable inputs including, but not limited to**:** load forecasts; generation output levels; Interchange; known Protection System status or degradation; and **Remedial Action Scheme** status or degradation**, functions, and limits**; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third -party services.)

Real -time Assessment (RTA) An evaluation of system conditions using Real time data to assess existing (pre- Contingency) and potential (post - The assessment shall reflect applicable inputs including, but not limited to: load**;** generation output levels**;** known Protection System status or degradation; and **Remedial Action Scheme** status or degradation**, functions, and limits;** Transmission outages**;** generator outages**;** Interchange**;** Facility Ratings**;** and identified phase angle and equipment limitations. (Real -time A third party services.) PSEG, Segment(s) 5, 6, 1, 3, 3/10/2016	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
In alignment with the recent training related implementation plans, 24 months is more realistic to incorporate new requirements into existing training programs.	
Likes 0	
Dislikes 0	
Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	No
Document Name	
Comment	
PSEG thanks the drafting team for its efforts and appreciates having the opportunity to comment on the proposed OPA and RTA definitions. PSEG is in general agreement with the intent of the proposed OPA and RTA definitions as it applies to the inclusion of Protection Systems and RASs in evaluations and assessments (that would be conducted by operations personnel). The wording of the current version of each definition states that OPA evaluations	

and RTA assessments "…shall reflect applicable inputs including… known Protection System and Remedial Action Scheme status or degradation, functions, and limits…". PSEG agrees that OPAs and RTAs should include the status or degradation of known protection systems and RASs. Additionally, we believe that inclusion of the "functions and limits" of RASs in OPAs and RTAs would improve reliability. However, it is requested that the requirement to include the "functions and limits" of [all] known Protection Systems be removed from the OPA and RTA definitions. As they are currently written, the definitions imply that the (operations) personnel who perform OPAs and RTAs would require detailed information regarding the settings for all protection systems (or schemes) that are within their scope of operations in order to complete OPAs and RTAs. PSEG does not believe that this level of detail regarding [all] protection systems is necessary in OPAs and RTAs in order to maintain reliability of the BES. PSEG therefore proposes that the definitions be revised as follows: **Operational Planning Analysis (OPA)** An evaluation of projected system conditions to assess anticipated (pre -Contingency) and poten ons for next day operations. The evaluation shall reflect applicable inputs including, but not limited to**:** load forecasts; generation output levels; Interchange; known Protection System status or degradation; and **Remedial Action Scheme** status or degradation**, functions, and limits**; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third -party services.) **Real -time Assessment (RTA)** An evaluation of system conditions using Real -time data to ass ting conditions. The assessment shall reflect applicable inputs including, but not limited to: load**;** generation output levels**;** known Protection System status or degradation; and **Remedial Action Scheme** status or degradation**, functions, and limits;** Transmission outages**;** generator outages**;** Interchange**;** Facility Ratings**;** and identified phase angle and equipment limitations. (Real -time Assessments may be provided through internal systems or through third -party services.)	
Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
An implementation plan of 12 months is insufficient, as it may not allow larger entities adequate time to improve the existing training program under PRC-001 R1. This shortened duration may force large entities to continue utilizing PRC-001 training processes for PER-006-1, which may not meet the auditor's intent. Instead, AEP recommends that a 4 year phased implementation period for the Standard be incorporated as follows: specific training	

of personnel would consist of 40% within 12 months, 60% within 24 months, 80% within 36 months, and 100% within 48 months following the effective date of the Standard.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Essential Power, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bradley Collard - SunPower - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rob Collins - Rob Collins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

7. Are you aware of any conflicts between the proposed PER-006-1 Reliability Standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If so, please identify the conflict here.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP is not aware of any potential conflicts between the proposed PER-006-1 Reliability Standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	No
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	

No Comment

Likes 0	
Dislikes 0	

Response
John Fontenot - Bryan Texas Utilities - 1,5

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Minh Ngo - City of Garland - 3,5,6

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Erika Doot - U.S. Bureau of Reclamation - 5

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Rob Collins - Rob Collins	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Bradley Collard - SunPower - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Generation	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Essential Power, LLC - 5	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Oshani Pathirane - Oshani Pathirane

Answer	
Document Name	

Comment
N/A

Likes 0	
Dislikes 0	

Response

8. Are you aware of the need for a regional variance or business practice that should be considered with this project? If so, please identify it here.

Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	No
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP is not aware of any potential need for a regional variance or business practice that should be considered with this project.	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Essential Power, LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Generation	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rob Collins - Rob Collins	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane	
Answer	Yes
Document Name	
Comment	
Within the province of Ontario, many Ontario Market Rules published by Ontario’s Independent Electricity System Operator (IESO) contain requirements that mandate adequate knowledge of system operating staff. Hence, in Ontario, the IESO Market Rules already encompass many of the requirements in this standard for Generator Operators. Similarly, other ISOs may also have pre-defined requirements for operators within their jurisdictions to hold their system operating staff accountable for prior to issuing a transmission or generating license.	
Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

9. If you have any other comments not previously mentioned above, please provide them here:	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	
Document Name	
Comment	
na	
Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	
Document Name	
Comment	
In agreement with comments submitted by ACES.	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	

Reclamation supports the drafting team's effort to move the GOP Protection System training requirement to a Personnel Performance, Training, and Qualification (PER) standard. Reclamation suggests that in the future, PER-006 could be revised to include other one-off GOP training requirements, like the minimum of two hours of GOP blackstart training required every two calendar years in EOP-005 R17. Reclamation appreciates the drafting team's industry outreach and approach to relying on the existing PER-005-2 Systematic Approach to Training standard to replace PRC-001 R1 for BAs, RCs, TOPs, and GOP centrally located dispatch centers, rather than creating duplicative requirements.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP supports the overall efforts and direction of the project team. Our negative vote on the standard is driven solely by our objections to the implementation plan, as expressed in our response to Question #6.	
Likes 0	
Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	
Document Name	
Comment	
PER-006-1; Top of Page 4 says; "When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material section of the standard."	

Is this the most updated NERC template, from other standards we have reviewed, we thought that the Rationale boxes were going to stay with the Requirements after approved. Please advise.

Likes 0	
Dislikes 0	

Response
Angela Gaines - Portland General Electric Co. - 3

Answer	
Document Name	

Comment

- The RSAW requests documentation of Protection System and RAS changes, but there is no mention of how the auditors will use this list to measure compliance if there is no frequency for training. As the standard is written, there is no timeframe for training operators on these changes.
- Without any requirement in this standard for the TOP to notify the GOP of changes to the Protection Systems and RAS, PGE sees a gap in the compliance monitoring for this when the TOP for several plants is a different entity.

Likes 0	
Dislikes 0	

Response
Don Schmit - Nebraska Public Power District - 5

Answer	
Document Name	

Comment

ADDITIONAL COMMENTS:

#1: Suggessted sub-requirement for this Standard under R1

R1.1: the Generator Operator shall determine when its plant personnel need to receive additional training, such as new systems, replacements, technology and operational functionality, of Protection Systems and RAS.

Add the following to Measurement 1: Documentation of changes or additions during the compliance monitoring period that effect the output of the generating facility(ies). #2: Within the proposed PER-006-1 RSAW in relation to R1, there is a note to the auditor (page 5), which states that “Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes that affect the output of the Facility”. The Guidelines and Technical Basis within the Standard, under R1, (page 9 of 10, second paragraph) states “On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS”. To maintain the intent of the drafting team we propose that the *note to the auditor* reflect the drafting teams intent from the Guidelines and Technical Basis section.We recommend the following wording that reflects the SDT’s intent: NOTE TO AUDITOR: Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes that affect the output of the Facility; however the Generator Operator has the flexibility to determine when its personnel need to receive additional training (new systems, replacements, technology, and operational functionality) on the operational functionality of Protection Systems and RAS.

Likes 0	
Dislikes 0	

Response

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	

Comment
Within the proposed PER-006-1 RSAW in relation to R1, there is a note to the auditor (page 5), which states that “Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes that affect the output of the Facility”. The Guidelines and Technical Basis within the Standard, under R1, (page 9 of 10, second paragraph) states “On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS”. The NSRF wants to maintain this intent of the drafting team and we propose that the *note to the auditor* reflect the drafting teams intent from the Guidelines and Technical Basis section. The NSRF recommends the following wording that reflects the SDT’s intent. NOTE TO AUDITOR: Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes that affect the output of the Facility; **however the Generator Operator has the flexibility to determine when its personnel need to receive additional training**

(new systems, replacements, technology, and operational functionality) on the operational functionality of Protection Systems and RAS. (Bold is additional recommended text.)	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	

Even though the PER-006-1 draft standard aids in ensuring that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the BES, ReliabilityFirst believes the requirement fall short as there is no periodicity of training noted in the requirement. ReliabilityFirst provides the following comments for consideration:

1. Requirement R1

    i. Even though the “Guidelines and Technical Basis” states “The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service.”, the actual requirement has no periodicity requirements. If the true intent of the SDT is to have the GOP personnel receive training before the Protection Systems or RAS is placed into service, ReliabilityFirst believes this language should be added to the Requirement. ReliabilityFirst also seeks clarification on the timing of when new personal are required to receive this training (e.g., is it required prior to going on shift for the first time). Also is it the expectation of the SDT that existing personal are required to receive this training by the time this standard becomes effective? If this is the case, the SDT may want to consider including this in the Implementation Plan. ReliabilityFirst offers the following for consideration:

        a. Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1., on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies) it operates, [either prior to new personnel going on shift for the first time or prior to Protection Systems or RAS placed into service].

Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	

Answer	
Document Name	
Comment	
Southern Company is in agreement with the draft standard PER-006-1 and revisions to the definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA).	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	
Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Council- Standards Review Committee (SRC).	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	
Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Council- Standards Review Committee (SRC).	
Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Thank you to the SDT for breaking this out and creating a new PER standard. SRP supports this action and appreicates the efforts taken to make this happen.	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	
Document Name	
Comment	
With regard to the structure of PER-006-1: In this case, a new standard, containing a single requirement, is proposed to require GOPs train on "operational functionality specific to Protection Systems and Remedial Action Schemes and their effects on generating Facilities." This is a deviation from past practice whereby prior GOP training requirements, such as that for system restoration from Blackstart Resources (EOP-005-2, R17) and communication (COM-002-4, R3), have been included with the subject matter material as opposed to a Personnel Performance, Training and Qualifications (PER) standard. APS recommends NERC consider (as part of a future effort and assuming PER-006-1 is adopted) whether it would make sense to migrate all GOP training requirements under PER-006-1. Alternatively, this training requirement could be placed within an appropriate Protection and Control (PRC) standard, although with the retirement of PRC-001-1(ii), there does not appear to be an ideal location for this requirement.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Generation	
Answer	
Document Name	

Comment	
The SDT needs to ensure that the RSAW aligns with PER-006-1 intent. Currently the draft RSAW for PER-006-1 specifies the following evidence requested to demonstrate compliance. "Documentation of changes or additions during the compliance monitoring period to Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies)." This requested evidence does not align with the current version of PER-006-1. Per the "Guidelines and Technical Basis" the "periodicity for training is not specified in Requirement R1 because it is incumbent upon the GOP to ensure its plant personnel … … are trained in order to operate the plant." And further states that "the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.)" Although it would seem entirely reasonable for a functional change to warrant additional training, the evidence request in the RSAW could be broadly interpreted that ALL changes, regardless of impact or non-impact to the functionality of the Protection System, would require training prior to implementation. This is an unnecessary burden on the GOP and in Exelon's opinion was not the intent of the SDT.	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	
Document Name	
Comment	
The purpose of the standard as drafted in section A.3, "topics essential to Reliability to perform or support," is worded awkwardly. The topics are not directly essential to Reliability. Performance and support of Real-Time operations should be the subject of the topics. The standard should apply to training on topics regarding only those Real-time operations that are essential to Reliability of the BES. Accordingly, TVA suggests the purpose should state, "To ensure that personnel are trained on specific topics regarding performance or support of Real-time operations essential to reliability of the Bulk Electric System." The RSAW requires the following evidence: • Identification of responsible personnel • Identification of the set of Protection Systems and Remedial Action Schemes that affect the output of the generating facility(ies). • Evidence that the identified personnel completed the training	

- Documentation of changes or additions to the identified Protection Systems and Remedial Action Schemes

This expectation is presented in both the “Evidence Requested,” and in the “Assessment Approach” sections of the RSAW. However, this seems to introduce new requirements and measurements in the RSAW beyond what is stated in the draft standard. The measurement of compliance as stated in the standard is simply that,

“Each Generator Operator shall have available for inspection, evidence that the applicable personnel completed training.”

TVA acknowledges that maintaining a list of applicable personnel is essential to meeting the stated measure. However, the RSAW expectation to provide a list of Protection Systems and Remedial Action Schemes, as well as documentation of changes or additions to these systems, expands the scope of required evidence to include the adequacy of the training content, which is not addressed in either in the Requirement or the Measure as drafted. At first blush, these new requirements appear to be supported by the statement in the "Guidelines and Technical Basis" section of the standard which states,

"The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service."

However, it is immediately refuted by the next sentence which states,

"On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e .g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS."

TVA respectfully requests that the drafted standard (Measure and Guidelines/Basis) and the RSAW be aligned to remove the ambiguity, 1) between statements in the Guidelines and Technical Basis as previously described, and 2) between the RSAW and the standard Measure. The RSAW should be revised to remove expectations for maintaining documentation of the set of Protection Systems and Remedial Action Schemes and changes or additions to these systems and schemes.

Likes 0	
Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1

Answer	
Document Name	

Comment

ADDITIONAL COMMENTS:

#1: Suggessted sub-requirement for this Standard under R1

R1.1: the Generator Operator shall determine when its plant personnel need to receive additional training, such as new systems, replacements, technology and operational functionality, of Protection Systems and RAS.

Add the following to Measurement 1: Documentation of changes or additions during the compliance monitoring period that effect the output of the generating facility(ies). #2: Within the proposed PER-006-1 RSAW in relation to R1, there is a note to the auditor (page 5), which states that "Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes that affect the output of the Facility". The Guidelines and Technical Basis within the Standard, under R1, (page 9 of 10, second paragraph) states "On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS". To maintain the intent of the drafting team we propose that the *note to the auditor* reflect the drafting teams intent from the Guidelines and Technical Basis section.We recommend the following wording that reflects the SDT's intent: NOTE TO AUDITOR: Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes that affect the output of the Facility; however the Generator Operator has the flexibility to determine when its personnel need to receive additional training (new systems, replacements, technology, and operational functionality) on the operational functionality of Protection Systems and RAS.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	
Document Name	
Comment	
No other comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	
Comment	
PacifiCorp believes that a new standard, PER-006, would be superfluous to PER-005. An entirely new standard only increases compliance documentation burden without any incremental increase in reliability to the BES. The proposed changes could be made in a new version of PER-005-2, identified as PER-005-3. Both PER-005-2 and the current PER-006 address the same issue. As standards are rewritten, training requirements need to be consolidated not only within the PER section but within the same standard. This would provide consistent approach and reduce the possibility of conflicting terms and applications.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE noticed there is no explanation for the term “calendar year” in the Evidence Retention section of PER-006-1. Footnote #3 of Table 1-1 in PRC-005-6 explains how to apply the term calendar year in PRC-005-6. Is the intent that the term calendar year in PER-006-1 be applied the same as it is applied in PRC-005-6?

Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	
Document Name	
Comment	
SRC would like to recognize the willingness of the project team to move away from the initial TOP-009 proposed standard based on the majority comments received from the industry. In addition, the numerous outreach efforts by the project team was instrumental in understanding the industry comments and arriving at the right solution at the end. This is a good example of how the existing iterative process will yield the right results when given the opportunity. Thank you.	
Likes 0	
Dislikes 0	
Response	

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	
Document Name	
Comment	

According to the accompanying RSAW “Documentation of changes or additions during the compliance monitoring period to Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies)” will be requested as evidence for PER-006-1 R1. Tri-State believes there is no corresponding requirement in the current draft of PRC-006-1 that suggests this information is necessary. If it was the SDT’s intentions that there be additional training prior to implementing any changes to the Protection Systems or RAS that affect the output of the Facility, then there should be a requirement that explicitly states that. Tri-State suggests that the SDT create a requirement or sub-requirement to require entities to provide new or additional training to its plant personnel prior to the change in the Protection Systems and RAS being made, so that they are aware of the operational functionality.

We heard in one of the Q&A sessions that the operators at a dispatch center could be included if they have direct control, in Real-time, of an unmanned plant via remote access capabilities. While we don't disagree with this inclusion, the applicability section does not convey this. We would suggest that the SDT include this scenario within the applicability section.

Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane	
Answer	
Document Name	
Comment	

N/A

Likes 0	
Dislikes 0	
Response	

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2007-06.2 Phase 2 of System Protection Coordination | PER-006-1 and Modified Definitions of OPA and RTA

Comment Period Start Date: 3/10/2016

Comment Period End Date: 4/25/2016

Associated Ballots: 2007-06.2 Phase 2 of System Protection Coordination Modified Definitions of OPA and RTA IN 1 DEF, 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 IN 1 ST, and 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 Non-binding Poll IN 1 NB

There were 54 responses, including comments from approximately 126 different people from approximately 93 different companies representing 8 of the 10 Industry Segments as shown on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards Development, Steve Noess (via email) or at (404) 446-9691.

Summary

There were two significant themes regarding the proposed PER-006-1 (*Specific Training for Personnel*) Reliability Standard that were submitted by industry. The first theme was a concern that the PER-006-1 did not have a periodicity requirement. The second theme was expansion of the periodicity concepts discussed in the Guidelines and Technical Basis of the PER-006-1 Supplemental Material section. These same concepts were carried over to the Reliability Standard Audit Worksheet (RSAW) and did not align with the Requirement R1 language. To address these two themes, the drafting team revised the Guidelines and Technical Basis to improve clarity on the intent and proposed revisions to the RSAW, a NERC Compliance document.

There was one significant theme regarding the proposed modifications to the definitions of “Operating Planning Analysis” (OPA) and “Real-time Assessment” (RTA) concerning “functions and limits.” The drafting team agreed with comments about using the term “limits” and has replaced it with “limitations” because it more clearly articulates the drafting team’s intent of the proposed modification to the definitions. The term “limitations” reflects that there may be various “limits” given the circumstances and inputs into the OPA and RTA.

There were a small number of comments concerning the Implementation Plan time frame, the drafting team increased the implementation period of PER-006-1 from 12 months to 24 months following applicable regulatory approval. Based on the Implementation Plan, the Generator Operator will have 24 months to implement PER-006-1 upon the applicable approval before Requirement R1 of PRC-001-1.1(ii) (*System Protection Coordination*) is retired. This also means that the modifications to the definitions of OPA and RTA implementation will be increased to 24 months and not become effective until the retirement of PRC-001-1.1(ii) to avoid a gap in reliability. The remaining PRC-001-1.1(ii) Requirements R2, R5, and R6 could retire as earlier as March 31, 2017 or a later date provided by the regulatory authority. Earlier retirement is allowed because the drafting team explains how Requirements R2, R5, and R6 are covered by other standards that will become effective in 2017. Requirements R3 and R4 that were revised and moved to the NERC Board adopted PRC-027-1 (*Coordination of Protection Systems for Performance During Faults*) will retire 24 months following applicable regulatory approval.

There were a number of varying comments about the Guidelines and Technical Basis. The drafting team made modifications based on the comments to improve clarity and alignment with the PER-006-1 RSAW. Other comments were individual in nature and the responses to those along with the comments summarized here will be found with each entity comment.

Questions

1. **Generator Operator: Do you agree that the proposed PER-006-1 – Specific Training for Personnel appropriately replaces the responsibilities of the Generator Operator in PRC-001-1.1(ii) – System Protection Coordination, Requirement R1 (i.e., "…be familiar with the purpose and limitations of Protection Systems schemes…")? If not, please explain and provide suggestions to improve the PER-006-1 requirement.**

2. **Transmission Operator: The reliability objective of PRC-001-1.1(ii), Requirement R1 for the Transmission Operator (i.e., "…be familiar with the purpose and limitations of Protection Systems schemes…"), that is not already covered by the *Personnel Performance, Training, and Qualifications* (PER) Reliability Standards, is addressed by inserting the phrase "functions, and limits" into the proposed modified definitions of OPA and RTA. The Transmission Operator, by integrating the "functions and limits" of Protection Systems and Remedial Action Schemes into its OPA and RTA, will ensure that the Bulk Electric System is operated within System Operating Limits (SOL) and Interconnection System Operating Limits (IROL). Do you agree that the proposed modification of these terms as defined by the *Glossary of Terms Used in NERC Reliability Standards* achieves this reliability objective? If not, please explain and provide suggestions.**

3. **Reliability Coordinator: During the progression of Project 2007-06.2, it was determined that the Reliability Coordinator, a function that is not applicable to PRC-001-1.1(ii) should, similarly, "…be familiar with the purpose and limitations of Protection Systems schemes…" as found in Requirement R1 of the standard. The reliability objective for the Reliability Coordinator that is not already covered by the PER Reliability Standards, is being addressed by inserting the phrase "functions, and limits" into the proposed modified definitions of OPA and RTA. The Reliability Coordinator, by integrating the "functions and limits" of Protection Systems and Remedial Action Schemes into its OPA and RTA, will ensure that the Bulk Electric System is operated within SOL and IROL. Do you agree that the proposed modification of these terms as defined by the *Glossary of Terms Used in NERC Reliability Standards* achieves this reliability objective? If not, please explain and provide suggestions.**

4. **Do you agree with the proposed Violation Risk Factor (VRF) and Violation Severity Levels (VSLs) for the proposed PER-006-1 Requirement? If not, please provide a basis for revising the VRF and/or what would improve the clarity of the VSLs.**

5. **Do the PER-006-1, Application Guidelines provide sufficient guidance, basis for approach, and examples to support performance of the Requirement? If not, please provide specific detail that would improve the Application Guidelines.**

6. **Do you agree with implementation period (i.e., 12 months) of the proposed PER-006-1 Reliability Standard and the proposed definition modifications of OPA and RTA based on the considerations listed in the Implementation Plan? If not, please provide a justification for changing the proposed implementation periods.**

7. **Are you aware of any conflicts between the proposed PER-006-1 Reliability Standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If so, please identify the conflict here.**
8. **Are you aware of the need for a regional variance or business practice that should be considered with this project? If so, please identify it here.**
9. **If you have any other comments not previously mentioned above, please provide them here:**

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Exelon	Chris Scanlon	1		Exelon Generation	Vince Catania	Exelon	5	RF
					Dave Carlson	Exelon	6	RF
Public Service Enterprise Group	Christy Koncz	1,3,5,6	NPCC,RF	PSEG	Jeffrey Mueller	PSEG - Public Service Electric and Gas Co	5	RF
					Joseph Smith	PSEG - Public Service Electric and Gas Co.	6	RF
					Karla Jara	PSEG - Energy Resources and Trade LLC	1	RF
					Tim Kucey	PSEG - PSEG Fossil LLC	3	RF
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF

MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Amy Casucelli	Xcel Energy	3,4,5,6	MRO
					Brad Perrett	Minnesota Power	1	MRO
					Chuck Lawrence	American Transmission Company	1,3,5	MRO
					Chuck Wicklund	Otter Tail Power Company	1,3,5,6	MRO
					Dave Rudolph	Basin Electric Power Cooperative	1,3,5,6	MRO
					Jodi Jenson	Western Area Power Administration	1,6	MRO
					Joe Depoorter	Madison Gas & Electric	4	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Larry Heckert	Alliant Energy	2	MRO

					Mahmood Safi	Omaha Public Utility District	1,3,5,6	MRO
					Mike Brytowski	Great River Energy	1,5	MRO
					Scott Nickels	Rochester Public Utilities	4	MRO
					Shannon Weaver	Midwest ISO Inc.	1,3,5,6	MRO
					Terry Harbour	MidAmerican Energy Company	3,4,5,6	MRO
					Tom Breene	Wisconsin Public Service Corporation	1,3,5	MRO
					Tony Eddleman	Nebraska Public Power District	1,3,5,6	MRO
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Bill Shultz	Southern Company Generation	3	SERC
					Jennifer Sykes	Southern Company Generation	5	SERC

						and Energy Marketing		
					Scott Moore	Alabama Power Company	6	SERC
Dominion - Dominion Resources, Inc.	Randi Heise	5		Dominion - RCS	Connie Lowe	Dominion Resources, Inc.	1	SERC
					Larry Nash	Dominion Virginia Power	6	SERC
					Louis Slade	Dominion Resources, Inc.	3	RF
					Randi Heise	Dominion Resources, Inc,	5	NPCC
California ISO	Richard Vine	2		ISO/RTO Council Standards Review Committee	Ali Miremadi	California ISO	2	WECC
					Ben Li	IESO	2	NPCC
					Charles Yeung	SPP	2	NPCC
					Greg Campoli	NYISO	2	Texas RE

					Kathleen Goodman	ISONE	2	MRO
					Mark Holman	PJM	2	NPCC
					Nathan Bigbee	ERCOT	2	RF
					Terry Bilke	MISO	2	SPP RE
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC No NextEra	Alan Adamson	New York State Reliability Council	1	NPCC
					Brian O'Boyle	Con Edison	NA - Not Applicable	NPCC
					Brian Robinson	Utility Services	1	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Bruce Metruck	New York Power Authority	1	NPCC
					David Burke	UI	2	NPCC
					David Ramkalawan	Ontario Power Generation	2	NPCC

					Edward Bedder	Orange & Rockland Utilities	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Gregory A. Campoli	NY-ISO	4	NPCC
					Guy Zito	Northeast Power Coordinating Council	5	NPCC
					Helen Lainis	IESO	6	NPCC
					Kathleen Goodman	ISO-NE	7	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Mark J. Kenny	Eversource Energy	1	NPCC
					Michael Forte	Con Edison	3	NPCC
					Michael Jones	National Grid	5	NPCC
					Michele Tondalo	UI	1	NPCC

					Paul Malozewski	Hydro One.	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Rob Vance	New Brunswick Power	1	NPCC
					Sean Bodkin	Dominion Resources Services, Inc	2	NPCC
					Si Truc Phan	Hydro Quebec	1	NPCC
					Sylvain Clermont	Hydro Quebec	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Bo Jones	Westar Energy	2	SPP RE
					Chris Dodd	Westar Energy	2	SPP RE
					J. Scott Williams	City Utilities of Springfield	3,5	SPP RE

					James Nail	Independence Power and Light	NA - Not Applicable	NA - Not Applicable
					Jason Smith	Southwest Power Pool Inc	1,3,5	SPP RE
					Michael Jacobs	Pattern Energy Group	NA - Not Applicable	NA - Not Applicable
					Mike Kidwell	Empire District Electric Company	1,3,5,6	SPP RE
					Robert Gray	Board of Public Utilities (City of McPherson)	1,3,5,6	SPP RE
					Shannon Mickens	Southwest Power Pool Inc.	1,3,5,6	SPP RE
					Stephanie Johnson	Westar Energy	1,4	SPP RE
Oxy - Occidental Chemical	Venona Greaff	7		Oxy	Michelle D'Antuono	Ingleside Cogeneration LP.	7	SERC

					Venona Greaff	Occidental Chemical Corporation	5	Texas RE

1. ***Generator Operator: Do you agree that the proposed PER-006-1 – Specific Training for Personnel appropriately replaces the responsibilities of the Generator Operator in PRC-001-1.1(ii) – System Protection Coordination, Requirement R1 (i.e., "…be familiar with the purpose and limitations of Protection Systems schemes…")? If not, please explain and provide suggestions to improve the PER-006-1 requirement.***	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	No
Document Name	
Comment	
It does not require the Generator Operator (GOP) to perform any verification activities of retention of the training following the training, nor does it address training refreshment. The results of this omission diverges from the structure established in PER-005-2 R1, R2, and R3, and would put the RE examiner in the position of testing all plant operators and assess their abilities to properly assign a VSL. It also follows that the RE examiner would have to be familiar with the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility. This could be a stretch for most examiners, and, at the very least, lengthen the time of preparation for examination.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. Requirement R1 does not require refreshment and is not intended to align with the systematic approach to training in PER-005-2 (*Operations Personnel Training*). The performance of the requirement is to provide training and not test the plant operator's retention of the training. Content of the operational functionality of the Protection Systems and Remedial Action Schemes (RAS) are the areas of focus and it is not intended for the auditor to question the depth of the content.	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5	
Answer	No

Document Name	
Comment	

M. LeRoy Patterson

System Operator Trainer

Grant County PUD (GCPD)

Ephrata, WA

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- The notion that PRC-001 R1 required training of Plant Operators is not supported historically or by plain reading of that requirement. While some personnel within GOPs had to be trained (i.e. "familiar with"), the requirement is silent regarding specific GOP personnel requiring such training. Oddly, the drafting team recognizes this and uses such an interpretation as it recommends changes to assessment definitions to bring PRC-001 requirements under PER-005 for BAs, TOPs, RCs, etc.

GCPD supports training in general and Plant Operator training specifically. Further, GCPD recognizes value in providing training to its employees, including Plant Operators.

That said, GCPD does not support PER-006 because there is no direct causal relationship between requiring training of Plant Operators and enhancing BES reliability benefits associated with Protection Systems and Remedial Action Schemes (RAS) other than the vague notion that training is always beneficial.

BES Reliability is affected adversely when Protection Systems and RAS are designed, implemented, and/or operated improperly. Of these three aspects, Plant Operators may have a role in their operation, but only from the standpoint of allowing such systems to be in service as directed or agreed upon by GOPs. For Protection Systems and RAS, which operate to protect equipment other than the unit being relayed offline, the GOP should be required to take agreed upon actions to place such systems in service and to keep such systems functional as long as the agreed upon conditions persist. This is the manner used to enforce having AVR and PSS in service.

For Protection Systems and RAS, which operate to protect the unit, GOPs have a stake in operating such systems appropriately. In addition, GOPs are required under existing requirements to coordinate regarding such systems with TOPs et al.

In both cases, it is likely GOPs provide training for Plant Operators to ensure proper operation of Protection Systems and RAS. However, mandating such training is specifying "how" to achieve an outcome rather than requiring a necessary performance. In both cases, requirements should be in place to operate such systems within design and implementation criteria because requiring training of Plant Operators will not achieve the desired result. In addition, training Plant Operators does nothing to ensure appropriate design and implementation of such protection systems, which presumably is included in remaining PRC requirements.

Hence, PER-006 does not accomplish an appropriate reliability objective.

- If approved, PER-006 requires development of training materials, training classes, tracking systems, creation of evidence, and other administrative efforts to demonstrate compliance with PER-006. These extra tasks incur additional costs without a direct causal justification explaining why these additional costs contribute to the reliability of the BES as stated previously.

- The reliability objective is better addressed by requiring protective systems be kept in service and functional much the same way as requirements for AVRs and PSSs.

Likes 0	
Dislikes 0	

Response

The drafting team thanks you for your comments. The drafting team believes that PER-006-1 (*Specific Training for Personnel*) provides clarity over PRC-001-1.1(ii) (*System Protection Coordination*), Requirement R1 to identify the appropriate personnel who must receive training (be familiar with). Not having PER-006-1 and its associated Guidelines would result in a reliability gap in the absence of PRC-001-1.1(ii). The Generator Operator personnel at a centrally located dispatch center is addressed by PER-005-2 (*Operations Personnel Training*) and does not address plant personnel as expected by PER-006-1. The PER-005-2 standard is based on a systematic approach

to training and would not ensure that training on Protection Systems and Remedial Action Schemes (RAS) is provided for plant personnel, which are not applicable to PER-005-2. A technical conference held by the drafting team revealed that stakeholders did not want the burden of a systematic approach to training to be applied to plant personnel.	
Don Schmit - Nebraska Public Power District – 5	
Answer	No
Document Name	
Comment	
See comments in question #5 AND at the end of these comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response in question #5.	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	No
Document Name	
Comment	
The PSEG Companies agree that PER-006-1 appropriately addresses the responsibilities of the Generator Operator, however we are concerned that the phrase “affect the output of the generating Facility(ies) it operates” could be interpreted to require the Generator Operator to have knowledge of Protection Systems or RAS several substations distant from its point of interconnection. In this case, the Generator Operator could be required to understand the operational functionality of protection systems that the Generator Operator has no knowledge of. PSEG does not believe that this is the intent of the Standard Development Team, and suggests revising	

Requirement 1 to state**: "**Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that are associated with the generator interconnection and affect the output of the generating Facility(ies) it operates."	
Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
The drafting team thanks you for your comments. The drafting team notes that Requirement R1 of PER-006-1 (*Specific Training for Personnel*) specifically references "it operates" to delineate the Protection Systems and Remedial Action Schemes (RAS) that are in purview for those identified personnel. The Guidelines and Technical Basis (Supplement Material section of PER-006-1) explains that the considerations of operational functionality could include "[r]esulting actions – tripping/closing of breakers; tripping of a generator step-up (GSU) transformer; or generator ramping/tripping control functions."	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Talen Energy respectfully requests that the "Note to Auditor" on p.4 of the draft RSAW be changed as follows: Present text: "The documentation provided, including training if provided, should be specific to the operational functionality of Protection Systems and Remedial Action Schemes that affect output of the Facility. Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies). See Application Guidelines for details on what protective systems are covered. Generally, the Requirement focuses on those systems that are related to the electrical output of the generator." Revised text: The documentation provided, including training if provided, need not be Facility-specific. If Facility-specific training is provided, however, it should be updated if necessary to address changes or additions to Protection Systems and Remedial Action	

Schemes (RAS) that affect the output of the generating Facility(ies). See Application Guidelines for details on what protective systems are covered. Generally, the Requirement focuses on those systems that are related to the electrical output of the generator. Rationale: Changes or additions to Protection Systems or RASs would necessitate revisions to course materials and re-education of operators only if the training being given is Facility-specific, and PER-006-1 does not impose a requirement or even make a suggestion in this respect. The explanation of the term, "operational functionality," in the Guidelines and Technical Basis section of the standard does not include anything that would require training to be individualized for each plant, and the bullet points on p.9 of PER-006-list only topics of a general nature. The standard permits plant-specific training, but the Guidelines and Technical Basis material emphasizes the GOP's flexibility, which the RSAW as presently written seems to be taking away."	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. The drafting team has proposed edits to the Reliability Standard Audit Worksheet (RSAW), NERC Compliance document, to address the perceived inconsistency between Guidelines and Technical Basis and the RSAW.	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The adjustments as made extend the training to the Plant personnel which previously the training requirements were for the System Operators. This removes the training requirement from the Control Center Personnel who are more likely to need the understanding.	
Likes 0	
Dislikes 0	
Response	

The drafting team thanks you for your comments. The drafting team notes that PER-006-1 (*Specific Training for Personnel*) applies to the plant personnel and PER-005-2 (*Operations Personnel Training*) applies to the centrally located dispatch personnel. Control center personnel in PER-005-2 has remained unchanged by this project.	
Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	No
Document Name	
Comment	
The PSEG Companies agree that PER-006-1 appropriately addresses the responsibilities of the Generator Operator, however we are concerned that the phrase “affect the output of the generating Facility(ies) it operates” could be interpreted to require the Generator Operator to have knowledge of Protection Systems or RAS several substations distant from its point of interconnection. In this case, the Generator Operator could be required to understand the operational functionality of protection systems that the Generator Operator has no knowledge of. PSEG does not believe that this is the intent of the Standard Development Team, and suggests revising Requirement 1 to state**: “**Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that are associated with the generator interconnection and affect the output of the generating Facility(ies) it operates.” PSEG, Segment(s) 5, 6, 1, 3, 3/10/2016	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. The drafting team notes that Requirement R1 of PER-006-1 (*Specific Training for Personnel*) specifically references “it operates” to delineate the Protection Systems and Remedial Action Schemes (RAS) that are in purview for those identified personnel. The Guidelines and Technical Basis (Supplemental Material of PER-006-1) explains that the	

considerations of operational functionality could include "[r]esulting actions – tripping/closing of breakers; tripping of a generator step-up (GSU) transformer; or generator ramping/tripping control functions."

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	No
Document Name	
Comment	
Yes, however, FirstEnergy is voting NEGATIVE on the 1st Draft version due to concerns with text in the Guidance and Technical basis section of the standard. See question # 5 for more information.	
Likes 0	
Dislikes 0	
Response	
The PER-006-1 (*Specific Training for Personnel*) Guidelines and Technical Basis (Supplemental Material section of PER-006-1) been revised to remove the sentence "The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service" as noted in the above comment. The drafting team notes that the considerations of operational functionality are examples and are provided for guidance.	

Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
See comments in question #5 AND question #9 at the end of these comments.	
Likes 0	

Dislikes 0	
Response	
Please see the responses in questions 5 and 9.	
Douglas Webb on Behalf of: Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1	
Answer	No
Document Name	
Comment	

Kansas City Power and Light Company recommends withdrawal of PER-006-1 and its associated guideline, and offers an alternative to address GOP duties under proposed retired Standard PRC-001-1.1(ii). The recommendations are based on the following:

Generator Operator Not Equivalent to Plant Operators: PER-006-1 does not replace the responsibilities of the Generator Operator in PRC-001-1.1(ii). To replace one with the other would suggest parity between the two—an apple-to-apple change. Generator Operator in PRC-001-1.1(ii) applicability is at the entity level. The applicability under PER-006-1 is completely different, narrowly construed, creating a compliance duty on plant operators located at a generator's plant site and, as such, provides an apples-to-oranges change.

Generator Operator (GOP) is defined as, "The entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services [effective 07-01-2016]," referring to the responsibilities at the entity level. The Applicability for PER-006-1 establishes the compliance obligation at the operator—the individual person—level, with the effect of defining what a plant generator operator is and what an operator is not.

While establishing duties of system operators is not foreign in NERC Standard Requirements, in this particular case, we do not believe it is necessary.

GOP Already Responsible for Reliable Operation of Its System: The GOP and, in many situations, its delegates, carry a fundamental responsibility to supply energy in a manner that is not disruptive to the reliability of the Bulk Electric System (BES). If fulfilling that responsibility requires the GOP's lever-pullers, so to speak, at the generating plant to have awareness of Protection Systems and RAS, it is incumbent on the GOP to offer that awareness training whether a specific Standard exists or not. The GOP is in the best position to identify what training operators need to reliably manage their systems on the BES. This idea is reflected in soon to be enforceable, PER-005-2, Application Guidelines, Rationale for R6:

"The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods."

PER-005-2 applies to GOP control room operators, specifically excluding the generation facility operators. However, if the GOP, as the expert in its system and using a systematic method as provided in the guidelines, believes the generation facility operator needs to have awareness of Protection Systems and RAS, the GOP is going to extend awareness training to the generation facility operator because of the GOP's overarching duty to operate its system reliably with or without the onus of PRC-001-1.1(ii) or the proposed PER-006-1.

Every System is Unique: Remedial Action Schemes (RAS) are not applicable to all generators. Establishing a compliance duty under a Standard with a single Requirement to address a potential system design is inefficient and creates a challenge for entities that do not have relevant generator related RAS. In such a case, the entity has to prove a negative to show compliance; such an effort is often overly burdensome and, frankly, does little to promote reliability of the BES.

PER-005-2 Already Establishes GOP Training Responsibilities: To address the retirement of PRC-001-1.1(ii), we believe additional language to PER-005-2 Applicability 4.1.5.1 can effectively provide for the awareness training sought under proposed PER-006-1.

KCP&L suggests the following:

1. Withdraw PER-006-1 and its associated Guidelines.

2. Add language along the lines of the following as a bullet point following PER-005-2, Applicability 4.1.5.1:

- While the specific training set forth in this Standard is not applicable to plant operators located at a generator plant site, should the GOP determine there are systems or facilities that may impact the reliable operation of the Bulk Electric System (BES) and are relevant to the performance of plant operators' duties located at a generator plant site, the applicability may be extended

to include plant operators at a generator plant site for the narrow purpose--to incorporate awareness training of specific systems or facilities that impact the BES. Such awareness training shall be incorporatedd into the GOP's systematic training methodology.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. The drafting team believes that PER-006-1 (*Specific Training for Personnel*) provides clarity over PRC-001-1.1(ii) (*System Protection Coordination*), Requirement R1 to identify the appropriate personnel who must receive training (be familiar with). (1) Withdrawing PER-006-1 and its associated Guidelines and Technical Basis (Supplemental Material section of PER-006-1) would result in a reliability gap in the absence of PRC-001-1.1(ii). The Generator Operator personnel at a centrally located dispatch center is addressed by PER-005-2 (*Operations Personnel Training*) and does not address plant personnel as expected by PER-006-1. (2) The PER-005-2 standard is based on a systematic approach to training and would not ensure that training on Protection Systems and Remedial Action Schemes (RAS) is provided for plant personnel, which are not applicable to PER-005-2. A technical conference held by the drafting team revealed that stakeholders did not want the burden of a systematic approach to training to be applied to plant personnel. It is not the intent of the drafting team to have the Generator Operator provide training on Remedial Action Schemes if they do not that affect the output of the generating Facility(ies) it operates.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
We have several concerns that the intents of the drafting team haven't been accurately captured after participating in the Webinar (April 5, 2016). In reference to the term 'plant personnel', a drafting team member stated on the webinar that the "term wasn't just applicable to the operator but all staff and this supporting data could be found in the Technical Materials". We agree that this topic of discussion can be found in the Technical Materials section (Page 9- Guidelines: last two sentence of the first paragraph). There are	

examples provided to show what personnel shouldn't be included however, there are not examples reflecting who should be included. We suggest the drafting team include some clarifying examples of what type of 'plant personnel' should be included somewhere in the Technical Documentation. Our suggested example list would consist of (Operators, Engineers, Analysis……etc). We feel that type of information provides value as well. Our second concern would be related to the Webinar (April 5, 2016) slides related to 'avoiding conflict with PER-005-2'. It is our understanding that PER-005-2 Standard addresses personnel at a centrally located dispatch center while PER-006 addresses GOP (plant personnel). However, our concern comes from the Applicability section 4.1.5.1 (last sentence) of PER-005-2. The language mentions the personnel who wouldn't be covered under the PER-005-2. The other personnel mentioned are those at a "centrally located dispatch center who relay dispatch instructions without making any modifications". If PER-006-1 is to cover all 'plant personnel', but PER-005-2 is to cover some 'plant personnel' it seems there is either overlap or a gap that needs to be clarified. We suggest the drafting team re-evaluate the second set of 'plant personnel' mentioned in the section above and determine of more clarity can be provided as to which personnel should and should not be included. Finally, our last concern is related to the required periodicity of training for the 'plant personnel'. The Standard (PER-006-1) nor its Technical Documentation states how often this training should be conducted. From the webinar information (April 5, 2016) it appears that the intent of the Drafting Team is that as the reliability needs change, the training should be re-performed in order to stay consistent with those changes. We feel that this intent is not being conveyed in the Standard or its supporting documentation. Without further clarification, our interpretation is that only **one** training session needs to be conducted to meet the reliability and compliance needs. Either additional language specifying training conducted in relation to changes to the RAS function, or a period of time that training should be conducted needs to be added. Our review group suggests the drafting team use similar language implemented into Requirement R6 of PER-005-2. That language requires training conducted each calendar year and is listed as follows: "Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training".	
Likes 0	
Dislikes 0	
Response	

The drafting team thanks you for your comments. The personnel that are applicable to the PER-006-1 (*Specific Training for Personnel*) Reliability Standard is clear by the use of the word "and" in Applicability 4.1.1.1: "Plant personnel who are responsible for the Real-time control of a generator 'and' receive Operating Instruction(s)…" The drafting team believes that including additional examples are not necessary for clarity. Requirement R1 does not require refresher training and is not intended to align with the systematic approach to training in PER-005-2 (*Operations Personnel Training*).	
Leo Bernier - AES - AES Corporation – 5	
Answer	No
Document Name	
Comment	
We believe the training on Radial Action Schemes is beyond the scope of the intent of the standard for a GOP.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. The drafting team included Remedial Action Schemes (RAS) in PER-006-1 (*Specific Training for Personnel*) to close an identified gap in PRC-0001-1.1(ii) (*System Protection Coordination*). A RAS is included in the PER-006-1 standard because it may affect the output of a generating Facility.	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	

The Bureau of Reclamation (Reclamation) supports PER-006-1 as an appropriate revision to the Generator Operator protection system training requirement in PRC-001-1 to address the reliability objective of operator familiarity with the “purpose and limitations of Protection Systems.” Reclamation believes that the proposed requirement includes meaningful clarification that training must address “the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of … generating Facility(ies).”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Essential Power, LLC - 5	
Answer	Yes

Document Name	
Comment	
The main concern however is to contain the scope of "operational functionality" to that required to understand how the Protection System generally operates and affects the plant and not to necessarily require specific detailed knowledge of actual settings, etc. such that operators are expected to become system protection or relay experts.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. The drafting team notes that the PER-006-1 (*Specific Training for Personnel*) Guidelines and Technical Basis (see Supplemental Material section of PER-006-1) explains that the considerations of operational functionality could include "[r]esulting actions – tripping/closing of breakers; tripping of a generator step-up (GSU) transformer; or generator ramping/tripping control functions." Actual settings are not intended to be included in operational functionality.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees that the proposed PER-006-1 appropriately covers the responsibilities of the Generator Operator in PRC-001-1.1(ii). However, we feel that the proposed PER-006-1 goes far beyond what is necessary to cover the responsibilities of the Generator Operator in PRC-001-1.1(ii) and protect the reliability of the Bulk Electric System. We feel that a basic understanding of and familiarity with protection systems and Remedial Action Schemes, as currently required, is adequate for promoting the reliability of the BES. Duke Energy does not believe that having generator specific training increases stability of the BES, and believes that the administrative effort, especially on larger utilities with numerous generating facilities, would be especially burdensome.	
Likes 0	

Dislikes 0	
Response	
The drafting team thanks you for your comments. The drafting team has addressed this concern by appending the PER-006-1 (*Specific Training for Personnel*) Guidelines and Technical Basis (see Supplemental Material section of PER-006-1) to note that Facility-specific (i.e., generator specific) training is not intended.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees the proposed PER-006-1 replaces the responsibilities of the Generator Operator in PRC-001-1.1(ii) (i.e., "…be familiar with the purpose and limitations of Protection Systems schemes…"). Texas RE suggest aligning the training with requirement with PER-005-2 R1.1.1 as to be done each calendar year. The Guidelines and Technical Basis document indicates that "[t]he structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service", but there is nothing indicating how often personnel should be trained.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. Requirement R1 of PER-006-1 (*Specific Training for Personnel*) does not require refresher training and is not intended to align with the systematic approach to training in PER-005-2 (*Operations Personnel Training*). The performance of the requirement is to provide training and not test the plant operator's retention of the training. Content of the operational functionality of the Protection Systems and Remedial Action Schemes are the areas of focus and it is not intended for the auditor to question the depth of the content.	

The Guidelines and Technical Basis (Supplemental Material section of PER-006-1) has been revised to remove the sentence "The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service."	
Ben Engelby - ACES Power Marketing – 6	
Answer	Yes
Document Name	
Comment	
We appreciate the SDT's efforts in developing this draft standard and thank the team for responding to our previous comments that recommended moving this requirement to the PER family of standards. We would like to point out that this standard is very specific with regard to the applicability section, and would hope that future standard projects do not attempt to consolidate other training standards and requirements to PER-006-1. There may be future unintended consequences if other training requirements were to be consolidated in this standard that is only applicable to a subset of plant personnel.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	

No Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP – 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator – 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. – 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli on Behalf of: Peter Colussy, Xcel Energy, Inc. , 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response
Rob Collins on Behalf of: Scotty Brown, Southern Indiana Gas and Electric Co., 1, 6, 5, 3

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steve Rawlinson - Southern Indiana Gas and Electric Co. – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. – 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	Yes
Document Name	
Comment	
Likes 1	Oxy - Ingleside Cogeneration LP, 5, D'Antuono Michelle
Dislikes 0	
Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP – 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Generation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority – 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company – 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. – 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane on Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	

Response

2. *Transmission Operator: The reliability objective of PRC-001-1.1(ii), Requirement R1 for the Transmission Operator (i.e., "…be familiar with the purpose and limitations of Protection Systems schemes…"), that is not already covered by the Personnel Performance, Training, and Qualifications (PER) Reliability Standards, is addressed by inserting the phrase "functions, and limits" into the proposed modified definitions of OPA and RTA. The Transmission Operator, by integrating the "functions and limits" of Protection Systems and Remedial Action Schemes into its OPA and RTA, will ensure that the Bulk Electric System is operated within System Operating Limits (SOL) and Interconnection System Operating Limits (IROL). Do you agree that the proposed modification of these terms as defined by the Glossary of Terms Used in NERC Reliability Standards achieves this reliability objective? If not, please explain and provide suggestions.*	
Oshani Pathirane on Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3	
Answer	No
Document Name	
Comment	
While Hydro One Networks Inc. agrees that an evaluation may be performed for an OPA, an evaluation cannot be performed in real-time for an RTA. An OPA may be conducted over a longer period as next-day operations (as opposed to real-time operations) are considered. However, as the term implies, an RTA is conducted in real-time and therefore constitutes a quicker determination of conditions as opposed to a more time-consuming and comprehensive analysis. Therefore, Hydro One suggests that the definition of RTA start off with "*A determination of system conditions*…". The definition of OPA may be left as is if the definition of RTA is modified as suggested. While Question #3 below pertains to the RC and does not pertain to Hydro One Networks Inc., Hydro One agrees with the NPCC that assurance that the BES is operated within SOLs and IROLs is separate from integrating the functions and limits of Protection Systems and Remedial Action Schemes into OPA an RTA. Further, Hydro One agrees with the NPCC that the term "limits" may imply SOLs and IROLs, which Protection Systems have little if not, any impact on. Therefore, the term "limitations" is a better substitute for the term "limits".	
Likes 0	
Dislikes 0	

Response	
The drafting team thanks you for your comments. The suggested changes are out of scope of this project. Thank you for your suggestion. The drafting team changed the term “limits” to “limitations” in both definitions. The term “limitations” was chosen based on comments and more clearly articulates the drafting team’s intent of the proposed modification to the definitions. The term “limitations” reflects that there may be additional circumstances and inputs into the Operational Planning Analysis (OPA) and Real-time Assessment (RTA). See also NPPC responses in question 3.	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
SRC does not agree with the modification of the OPA and RTA definitions. SRC believes that the existing PER standard covers the intended scope of PRC-001-1.1 and the change in the definitions of OPA and RTA goes beyond the original scope of PRC-001-1.1. Additionally, RCs have protection system and SPS knowledge and awareness requirements in the IRO standards. However, if the SDT still believes the change in the definition of OPA and RTA is required, then there are better alternative phrases that will improve current proposal. The inclusion of the term “functions, and limits” in OPA and RTA can be misinterpreted. In the existing Glossary of Terms Used in NERC Reliability Standards (updated February 19, 2016) there are 21 references to “limit” or “Limit”, with vast majority of them referencing thermal, voltage, and stability limits and/or SOL and IROL. SRC suggest SDT consider the following alternative phrases to "functions, and limits" that will eliminate future confusion: 1) operational functionality, 2) intended functions, and 3) functions and limitations. Additionally, removing the word “schemes” from the phrase “protection system schemes” in translating this requirement from PRC-001-1.1 to the RTA and OPA definitions introduces confusion. Per the definition in the NERC Glossary of Terms, a protection system could be anything from a single protective relay to a set of relays designed to address a specific problem such as the exclusions identified in the RAS definition. The proposed language could be interpreted to mean that RCs/BAs/TOPs must be aware of the functions and limits of every single relay in its area, greatly expanding the scope of the requirements in the IRO and TOP standards that	

reference the RTA and OPA. SRC recommends the drafting team to use the defined term "Composite Protection System" instead of "Protection System".	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. The technical conference in February 2016 concluded that Protection Systems and Remedial Action Schemes (RAS) would be addressed through the reliability–related tasks analysis by the Reliability Coordinator or Transmission Operator under PER-005-2 (*Operations Personnel Training*). Revisions to defined terms of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA) were made to ensure that Reliability Coordinators and Transmission Operators would incorporate Protection Systems and Remedial Action Schemes into these evaluations. The drafting team changed the term "limits" to "limitations" in both definitions. The term "limitations" was chosen based on comments and more clearly articulates the drafting team's intent of the proposed modification to the definitions. The term "limitations" reflects that there may be additional circumstances and inputs into the Operational Planning Analysis (OPA) and Real-time Assessment (RTA). The drafting team notes that the definitions of RTA and OPA are approved and include the terms Protection Systems and Remedial Action Schemes. This project proposes modifying the definitions to address the reliability objective that the Reliability Coordinator and Transmission Operator integrate the functions and limits of Protection Systems and Remedial Action Schemes to ensure the Bulk Electric System (BES) is operated within System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL). The drafting team discontinued the approach of using the term "Composite Protection System" based on stakeholder comments from previous postings during this project.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE is concerned there is no explicit training requirement for TOPs and RCs on operational functionality of Protection Systems and Remedial Action Schemes (RAS). PER-005-2 requires TOPs and RCs to develop a list of "reliability-related tasks" but it does not specify these tasks include Protection Systems and RASes. Texas RE is concerned that adding the terms "functions and limits" to the definitions do not ensure that each TOP will be familiar with the functions and limitations of its Protections Systems and RASes as they need to be in PRC-001-1.1(ii). Additionally, with regard to the proposed definitions, SOL and IROL exceedances are only one aspect of situational awareness necessary for reliable operation of the BES. In order to maintain situational awareness, a TOP should be aware of Protection Systems and RASs to operate the system regardless of whether it is within SOLs or IROLs. For example, TOPs might be aware of how a unit tripped due to operation of a RAS and how that would impact an SOL or IROL exceedance. But you might not necessarily understand the reason of the generator trip as a result of the RAS operation and therefore lack knowledge of the duration of generator outage and other pertinent information. The need for situational awareness beyond SOL and IROL exceedances is more important for the RC, as RCs are responsible for coordination among TOPs.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. A technical conference held by the drafting team in February 2016 concluded that Protection Systems and Remedial Action Schemes (RAS) would be addressed through the reliability–related tasks analysis by the Reliability Coordinator or Transmission Operator under PER-005-2 (*Operations Personnel Training*). Revisions to defined terms of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA) were made to ensure that Reliability Coordinators and Transmission Operators would incorporate Protection Systems and Remedial Action Schemes into these evaluations.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

As a best practice, ERCOT believes it is preferable to include requirements in the Reliability Standards rather than in definitions. Because requirements in definitions do not have associated measures or VRFs/VSLs, compliance and enforcement could be complicated.

ERCOT recognizes that the SDT's intent is to translate the requirement R1 of PRC-001-1.1 for the TOP and BA to "be familiar with the purpose and limitations of Protection System schemes applied in its area" to the RTA and OPA definitions used in the IRO/TOP standards. However, the change from the phrase "purpose and limitations of Protection System schemes" to the phrase "known Protection System and Remedial Action Scheme status or degradation, functions, and limits," is problematic for several reasons.

In the context of protection systems, SPSs, and RASs, the difference in meaning between "limits" and "limitations" is significant. The word "limits" in the proposed RTA and OPA definitions has the potential to be confused with system operating limits (SOLs). Requiring RCs and TOPs to consider SOLs for protection systems and RASs in RTAs and OPAs is unnecessary because GOs and TOs are already required to consider those SOLs for those facilities under FAC-008 R2.3 and R2.4.1 and FAC-008 R3.3 and R3.4.1. For this reason, ERCOT disagrees with Question 2's statement that the proposed definition changes "will ensure that the Bulk Electric System is operated within System Operating Limits (SOL) and Interconnection System Operating Limits (IROL)."

The word "limits" could also be misconstrued to mean limits on protection systems and RASs in the form of protection relay set points. Facility owners responsible for protection system maintenance and testing regularly collect and maintain relay set point information. However, this information has not been typically provided by facility owners to RCs and TOPs since Facility Ratings have been used to operate the system, and the set points for the majority of relays utilized to protect equipment are well beyond the Facility Ratings. Without guidance on which specific limit information is required, RCs and TOPs would potentially be required to consider an enormous number of relay set points, which are subject to constant change, making integration of this information into an RTA or OPA challenging and burdensome, without any meaningful reliability improvement. Furthermore, under the new IRO-008-2 Requirement R4, effective April 1, 2017, RCs are required to conduct an RTA every 30 minutes. Incorporating relay set point information into an RTA every 30 minutes means an RC would need to collect and incorporate large and constantly fluctuating data sets. This introduces a burdensome RC requirement without any discernible reliability benefit.

Introducing a "limit" to track under the RTA and OPA may also create confusion over the responsibility of the RC/TOP to respond to such a "limit" if reached or exceeded. If an RC/TOP is already operating to thermal limits, this additional limit is unnecessary and confusing. To avoid this confusion, ERCOT recommends the SDT replace the term "functions and limits," with either (in order of preference): 1.) "operational functionality," 2.) "intended functions," or 3.) "functions and limitations." ERCOT also recommends the

SDT provide examples of how an RTA or OPA can be performed and documented to show evidence that "known Protection System and Remedial Action Scheme status or degradation and operational functionality" have been incorporated.

Additionally, removing the word "schemes" from the phrase "protection system schemes" in translating this requirement from PRC-001-1.1 to the RTA and OPA definitions introduces confusion. Per the definition in the NERC Glossary of Terms, a protection system could be anything from a single protective relay to a set of relays designed to address a specific problem such as the exclusions identified in the RAS definition. The proposed language could be interpreted to mean that RCs/BAs/TOPs must be aware of the functions and limits of every single relay in its area, greatly expanding the scope of the requirements in the IRO and TOP standards that reference the RTA and OPA. SRC recommends the drafting team to use the defined term "Composite Protection System" instead of "Protection System".

ERCOT also recommends the SDT provide industry with guidance on distinguishing between "protection system schemes" and "protective relays" so as to avoid future confusion.

Likes 0	
Dislikes 0	

Response

Thank you for your suggestion. The drafting team changed the term "limits" to "limitations" in both definitions. The term "limitations" was chosen based on comments and more clearly articulates the drafting team's intent of the proposed modification to the definitions. The term "limitations" reflects that there may be additional circumstances and inputs into the Operational Planning Analysis (OPA) and Real-time Assessment (RTA).

The drafting team notes that the definitions of "Operating Planning Analysis" (OPA) and "Real-time Assessment" (RTA) are approved and include the terms Protection Systems and Remedial Action Schemes (RAS). This project proposes modifying the definitions to address the reliability objective that the Reliability Coordinator and Transmission Operator integrate the functions and limits of Protection Systems and Remedial Action Schemes to ensure the Bulk Electric System (BES) is operated within System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL). The drafting team discontinued the approach of using the term "Composite Protection System" based on stakeholder comments from previous postings during this project.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra

Answer	No
Document Name	
Comment	
While we support the proposed revision to the two terms to achieve the intended purpose, we do not agree with the words “and limits”. The word “limits” lends itself to be interpreted as the system operating limits or interconnection system operating limits on which the Protection Systems, etc. have little bearing on. We suggest to reword the above to “functions and limitations” or “functions, limitations” to more accurately reflect the intent of the training on composite protection systems and RASs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your suggestion. The drafting team changed the term “limits” to “limitations” in both definitions. The term “limitations” was chosen based on comments and more clearly articulates the drafting team’s intent of the proposed modification to the definitions. The term “limitations” reflects that there may be additional circumstances and inputs into the Operational Planning Analysis (OPA) and Real-time Assessment (RTA).	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
PER-005-2 requires a Systematic Approach to training for the Transmission Operator and Balancing Authority which includes the documented methodology of reliability related tasks addresses the PRC-001-1.1(ii) R1 requirement to "be familiar with the purpose and limitations of Protection System Schemes." The modification to these terms is NOT needed to achieve this reliability objective,	

since the training is already required as part of the PER-005 standard. Please explain how entities reading these definitions can relate that training on relays is needed by added the words "functions and limitations" to OPA and RTA.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. A technical conference held by the drafting team in February 2016 concluded that Protection Systems and Remedial Action Schemes (RAS) would be addressed through the reliability–related tasks analysis by the Reliability Coordinator or Transmission Operator under PER-005-2 (*Operations Personnel Training*). Revisions to defined terms of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA) were made to ensure that Reliability Coordinators and Transmission Operators would incorporate Protection Systems and Remedial Action Schemes into these evaluations.	
Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	No
Document Name	
Comment	
PSEG supports the PJM comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see the response to the PJM comments for question 2.	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	

Answer	No
Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Council- Standards Review Committee (SRC).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see the response to the ISO/RTO Council- Standards Review Committee (SRC) comments for question 2.	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	No
Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Council- Standards Review Committee (SRC).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see the response to the ISO/RTO Council- Standards Review Committee (SRC) comments for question 2.	

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA supports PER-006-1 applicability solely to Generator Operators. However, BPA does not support the revised Operational Planning Analysis (OPA) and Real-Time Assessment (RTA) definitions as part of this project. BPA's concern is the compliance and reliability ambiguity presented by including "functions and limits" without specific guidance and/or requirements for the implementation of those terms. BPA desires to have the revised definitions excluded from project 2007-06.2. BPA suggests including the language in new or revised Standard(s) requirements, with specific guidance that would allow entities to meet the requirements and implementation of "functions and limits", such as TOP-001 and/or TOP-002.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. The drafting team considered the approach of revising multiple Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) standards to address the "functions and limits" of Protection Systems and Remedial Action Schemes. However, the team along with outreach to industry, determined that a surgical modification to the definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA) over changing multiple standards was the best approach. The team did revise the proposed changes slightly by replacing "limits" with "limitations."	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	No
Document Name	
Comment	

PSEG supports the PJM comments on this question.	
Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Thank you for your comment, please see the response to the PJM comments for question 2.	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
Vectren supports a more clear use of "functions and limits" with respect to the transmission operators knowledge of Protection Systems. The transmission operators should have a clear understanding of the impacts of a Protections System on electrical facilities. Specifically, the operators should know and plan for the resulting state of facilities that would be outaged for a typical fault. Generally, most facilities will clear from breaker to breaker, but a SPS or RAS may energize or change state of other non-coincidental facilities. The transmission operator should know the "functions and limits" in the context of planning the extent of the outage. However, with the newer technology programmable relays, there are "function" statements inside of the relay that a system protection technician would know, but a transmission operator would not need to know. The same could be stated about limits. The programmable relays have many "limits" and timers inside the relay "functions" that the transmission operator does not need to know. Vectren agrees that limits, as it pertains to SOL's and IROL's, need to be used by the transmission operator. These limits are not in the same context as internal protection system "functions and limits" within a programmable relay.	
Likes 0	
Dislikes 0	

Response	
Thank you for your suggestion. The drafting team changed the term "limits" to "limitations" in both definitions. The term "limitations" was chosen based on comments and more clearly articulates the drafting team's intent of the proposed modification to the definitions. The term "limitations" reflects that there may be additional circumstances and inputs into the Operational Planning Analysis (OPA) and Real-time Assessment (RTA).	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	No
Document Name	
Comment	
Vectren supports a more clear use of "functions and limits" with respect to the transmission operators knowledge of Protection Systems. The transmission operators should have a clear understanding of the impacts of a Protections System on electrical facilities. Specifically, the operators should know and plan for the resulting state of facilities that would be outaged for a typical fault. Generally, most facilities will clear from breaker to breaker, but a SPS or RAS may energize or change state of other non-coincidental facilities. The transmission operator should know the "functions and limits" in the context of planning the extent of the outage. However, with the newer technology programmable relays, there are "function" statements inside of the relay that a system protection technician would know, but a transmission operator would not need to know. The same could be stated about limits. The programmable relays have many "limits" and timers inside the relay "functions" that the transmission operator does not need to know. Vectren agrees that limits, as it pertains to SOL's and IROL's, need to be used by the transmission operator. These limits are not in the same context as internal protection system "functions and limits" within a programmable relay.	
Likes 0	
Dislikes 0	
Response	

Thank you for your suggestion. The drafting team changed the term “limits” to “limitations” in both definitions. The term “limitations” was chosen based on comments and more clearly articulates the drafting team’s intent of the proposed modification to the definitions. The term “limitations” reflects that there may be additional circumstances and inputs into the Operational Planning Analysis (OPA) and Real-time Assessment (RTA).

Rob Collins on Behalf of: Scotty Brown, Southern Indiana Gas and Electric Co., 1, 6, 5, 3	
Answer	No
Document Name	
Comment	
Vectren supports a more clear use of “functions and limits” with respect to the transmission operators knowledge of Protection Systems. The transmission operators should have a clear understanding of the impacts of a Protections System on electrical facilities. Specifically, the operators should know and plan for the resulting state of facilities that would be outaged for a typical fault. Generally, most facilities will clear from breaker to breaker, but a SPS or RAS may energize or change state of other non-coincidental facilities. The transmission operator should know the “functions and limits” in the context of planning the extent of the outage. However, with the newer technology programmable relays, there are “function” statements inside of the relay that a system protection technician would know, but a transmission operator would not need to know. The same could be stated about limits. The programmable relays have many “limits” and timers inside the relay “functions” that the transmission operator does not need to know. Vectren agrees that limits, as it pertains to SOL’s and IROL’s, need to be used by the transmission operator. These limits are not in the same context as internal protection system “functions and limits” within a programmable relay.	
Likes 0	
Dislikes 0	
Response	
Thank you for your suggestion. The drafting team changed the term “limits” to “limitations” in both definitions. The term “limitations” was chosen based on comments and more clearly articulates the drafting team’s intent of the proposed modification to the definitions.	

The term “limitations” reflects that there may be additional circumstances and inputs into the Operational Planning Analysis (OPA) and Real-time Assessment (RTA).	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	No
Document Name	
Comment	
Domminion supports the position of PJM and ISO-NE related to the proposed modification of these terms as defined by the *Glossary of Terms Used in NERC Reliability Standards*. While we support the proposed revision to the two terms to achieve the intended purpose, we do not agree with the words “and limits”. The word “limits” lends itself to be interpreted as the system operating limits or interconnection system operating limits on which the Protection Systems, etc. have little bearing on. We suggest to reword the above to “functions and limitations” or “functions, limitations” to more accurately reflect the intent of the training on composite protection systems and RASs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the responses to PJM and ISO-NE in questions 2.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	

The proposal is to revise the RTA and OPA definitions to cover “RAS”, “functions” and “limits”. However, per these definitions a third party can perform the RTA and OPA for the TOP, and the BA is not even necessarily involved per future TOP standards. It is not clear that this proposal ensures the BA/TOP familiarity with Protection Systems related to “RAS”, “functions” and “limits”. Also, we have had an ongoing challenge determining who performs the GOP function; is it the folks at the “centrally located dispatch center” per PER-005-2 or is it the “plant personnel” per PER-006? Maybe in Functional Model these could be split into separate roles/registrations. Specific to PER-006, not requiring familiarity of Protection Systems for the GOP centrally located dispatch center folks may be a gap. NIPSCO presently complies with PRC-001-0 R1 with an approach that we believe will cover the requirement and revised definitions of Project 2007-06.2 Phase 2 and therefore is voting Affirmative, however we would like to see our concerns addressed. We appreciate the efforts of this SDT, especially the extensive outreach to stakeholders on this project.	
Likes 0	
Dislikes 0	
Response	
A technical conference held by the drafting team in February 2016 concluded that Protection Systems and Remedial Action Schemes (RAS) would be addressed through the reliability–related tasks analysis by the Reliability Coordinator or Transmission Operator under PER-005-2 (*Operations Personnel Training*). Revisions to defined terms of “Operational Planning Analysis” (OPA) and “Real-time Assessment” (RTA) were made to ensure that Reliability Coordinators and Transmission Operators would incorporate Protection Systems and Remedial Action Schemes into these evaluations. Please note that the OPA and RTA are not applicable to the Balancing Authority. The Generator Operator personnel at a centrally located dispatch center is addressed by PER-005-2 and does not address plant personnel as expected by PER-006-1 (*Specific Training for Personnel*).	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No

Document Name	
Comment	
While we support the proposed revision to the two terms to achieve the intended purpose, we do not agree with the words "and limits". The word "limits" lends itself to be interpreted as the system operating limits or interconnection system operating limits on which the Protection Systems, etc. have little bearing on. We suggest to reword the above to "functions and limitations" or "functions, limitations" to more accurately reflect the intent of the training on composite protection systems and RASs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your suggestion. The drafting team changed the term "limits" to "limitations" in both definitions. The term "limitations" was chosen based on comments and more clearly articulates the drafting team's intent of the proposed modification to the definitions. The term "limitations" reflects that there may be additional circumstances and inputs into the Operational Planning Analysis (OPA) and Real-time Assessment (RTA).	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ben Engelby - ACES Power Marketing - 6	
Answer	Yes
Document Name	
Comment	
The proposed modification of these terms achieves the reliability objective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
In our interpretation of the proposed changes to the definitions, the intent is that the TOP needs to be familiar with the 'functions and limits' of the Protection System and RAS so they can Identify and understand how those systems will impact system reliability and/or if that system reliability is reduced or threatened. Additionally, the operators must include this knowledge into their everyday process of analyzing and operating their portion of the system in reference to the (BES) SOL and IROL. Based on the presentations from the webinar (April 5, 2016), we interpret that the proposed changes are intended to ensure the Analysis Performance under PER-005-2 includes both the Protection System and RAS. If that is the case, we feel that the message may not be conveyed adequately in the	

mapping document. We suggest adding some footnotes or other language to the document stating why the Requirements are mentioned, however we're not sure that the end goal is sufficiently communicated in order to help the industry understand the proposed changes.

Additionally we suggest the drafting team consider whether the proposed changes to the definitions should be conducted independent of this project. There are already many moving pieces in this project and this only adds more confusion. Technically, there are five proposed Standards associated with this project and all depends on the retirement of PRC-001 and its Requirements. Adding two definitions from the previous TOP/IRO Project warrants its own attention.

Likes 0	
Dislikes 0	

Response

Operational Planning Analysis (OPA) and Real-time Assessment (RTA).The mapping document explains how the current PRC-001-1.1(ii) (*System Protection Coordination*), Requirements R1, R2, R5, and R6 are addressed by other Transmission Operations and Interconnection Reliability Operations, and Coordinator (TOP/IRO) Reliability Standards. This along with the proposed PER-006-1 (*Specific Training for Personnel*) and the revised definitions of OPA and RTA facilitates the complete retirement of PRC-001-1.1(ii). The mapping document is not intended to explain how an entity will incorporate Protection Systems and Remedial Action Schemes (RAS) into their OPA and RTA evaluations. The systematic approach to training under PER-005-2 (*Operations Personnel Training*) is the process by which the Reliability Coordinator and Transmission Operator will determine what training its personnel will receive on how these Protection Systems and Remedial Action Schemes are integrated into the evaluations.

The standard and definitions are proposed together because both are integral to the reliability objectives being maintained with the retirement of PRC-001-1.1(ii). Separating them into two different projects would prevent the project from advancing with the recent approval of PRC-027-1 (*Coordination of Protection Systems for Performance During Faults*) onto a filing with regulators.

Douglas Webb on Behalf of: Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Answer	Yes
Document Name	

Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC supports the proposed revisions because NERC's explanation matches ATC's expectation regarding the correct understanding of the new, undefined terms "functions" and "limits". For example, ATC correlates "functions" with "purpose" of Protection Systems and Remedial Action Schemes, which would mean understanding that there are different functions implemented by relaying such as undervoltage protection, overcurrent protection, impedance relaying, etc. Additionally, ATC understands "limits" to correlate with current PRC-001-1.1(ii) term "limitations", which would mean understanding the limitations of relaying such as overspeed generator protection will not clear a fault by design, a bus differential will not clear a fault outside of its zone of protection, pulling relay trips means a breaker won't trip if the relay sends a signal to trip, etc. This corresponds to ATC's understanding that "limits" does **not** refer to defining System Operating Limits due to relay settings, in cases where the relay setting produces a lower facility rating than the other connected equipment, because facility limits due to relay settings (or other equipment) are covered by NERC Standard FAC-008-3 R3.4.1 and the NERC Glossary of Terms definition for "System Operating Limit".	
Likes 0	

Dislikes 0	
Response	
Thank you for your suggestion. The drafting team changed the term “limits” to “limitations” in both definitions. The term “limitations” was chosen based on comments and more clearly articulates the drafting team’s intent of the proposed modification to the definitions. The term “limitations” reflects that there may be additional circumstances and inputs into the Operational Planning Analysis (OPA) and Real-time Assessment (RTA).	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli on Behalf of: Peter Colussy, Xcel Energy, Inc. , 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	
Document Name	
Comment	

N/A	
Likes 0	
Dislikes 0	
Response	

***3.** Reliability Coordinator: During the progression of Project 2007-06.2, it was determined that the Reliability Coordinator, a function that is not applicable to PRC-001-1.1(ii) should, similarly, "…be familiar with the purpose and limitations of Protection Systems schemes…" as found in Requirement R1 of the standard. The reliability objective for the Reliability Coordinator that is not already covered by the PER Reliability Standards, is being addressed by inserting the phrase "functions, and limits" into the proposed modified definitions of OPA and RTA. The Reliability Coordinator, by integrating the "functions and limits" of Protection Systems and Remedial Action Schemes into its OPA and RTA, will ensure that the Bulk Electric System is operated within SOL and IROL. Do you agree that the proposed modification of these terms as defined by the Glossary of Terms Used in NERC Reliability Standards achieves this reliability objective? If not, please explain and provide suggestions.*

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

Same comment as in Q2, above.

Likes 0	
Dislikes 0	

Response

Please see the response in question 2.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

I don't think RCs will ever be familiar with the purpose and limitations of PS schemes in their footprint; it is too vast an area. However this is not a "show stopper" for us since we are not an RC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	No
Document Name	
Comment	
Dominion supports PJM on the following comment: PJM agrees with the intention of the drafting team but believes there are better alternative phrases that will improve current proposal. The inclusion of the term “functions, and limits” in Operational Planning Analysis (OPA) and Real-time Assessment (RTA) can be misinterpreted. In the existing Glossary of Terms Used in NERC Reliability Standards (updated February 19, 2016) there are 21 references to “limit” or “Limit”, with vast majority of them referencing thermal, voltage, and stability limits and/or SOL and IROL. SRC suggest SDT consider the following alternative phrases to "functions, and limits" that will eliminate future confusion: 1) operational functionality, 2) intended functions, and 3) functions and limitations.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please see the response to PJM in question 3.	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	No
Document Name	
Comment	
PSEG supports the PJM comments on this question	
Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Thank you for your comment. Please see the response to PJM in question 3.	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	No
Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Council- Standards Review Committee (SRC).	
Likes 0	
Dislikes 0	
Response	

Thank you for referring to the comments of others. Please see the response to the ISO/RTO Council- Standards Review Committee (SRC) comments.	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	No
Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Council- Standards Review Committee (SRC).	
Likes 0	
Dislikes 0	
Response	
Thank you for referring to the comments of others. Please see the response to the ISO/RTO Council- Standards Review Committee (SRC) comments.	
Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	No
Document Name	
Comment	
PSEG supports the PJM comments on this question.	
Likes 0	
Dislikes 0	

Response	
Thank you for referring to the comments of others. Please see the response to the PJM comments.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	No
Document Name	
Comment	
While we support the proposed revision to the two terms to achieve the intended purpose, we do not agree with the words “and limits”. The word “limits” lends itself to be interpreted as the system operating limits or interconnection system operating limits on which the Protection Systems, etc. have little bearing on. We suggest to reword the above to “functions and limitations” or “functions, limitations” to more accurately reflect the intent of the training on composite protection systems and RASs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your suggestion. The drafting team changed the term “limits” to “limitations” in both definitions. The term “limitations” was chosen based on comments and more clearly articulates the drafting team’s intent of the proposed modification to the definitions. The term “limitations” reflects that there may be additional circumstances and inputs into the Operational Planning Analysis (OPA) and Real-time Assessment (RTA).	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	

Comment	
Comments: Please see response to question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to your comments in question 2.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE is concerned there is no explicit training requirement for and RCs on operational functionality of Protection Systems and Remedial Action Schemes (RAS). PER-005-2 requires TOPs and RCs to develop a list of "reliability-related tasks" but it does not specify these tasks include Protection Systems and RASes. Additionally, with regard to the proposed definitions, SOL and IROL exceedances are only one aspect of situational awareness necessary for reliable operation of the BES. In order to maintain situational awareness, the RC should be aware of Protection Systems and RASs to operate the system regardless of whether it is within SOLs or IROLs. For example, the RC might be aware of how a unit tripped due to operation of a RAS and how that would impact an SOL or IROL exceedance. But you might not necessarily understand the reason of the generator trip as a result of the RAS operation and therefore lack knowledge of the duration of generator outage and other pertinent information. The need for situational awareness beyond SOL and IROL exceedances is more important for the RC, as RCs are responsible for coordination among TOPs.	
Likes 0	

Dislikes 0	

Response

The drafting team thanks you for your comment. A technical conference by the drafting team in February 2016 concluded that Protection Systems and Remedial Action Schemes (RAS) would be addressed through the reliability–related tasks analysis by the Reliability Coordinator or Transmission Operator under PER-005-2 (*Operations Personnel Training*). Revisions to defined terms of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA) were made to ensure that Reliability Coordinators and Transmission Operators would incorporate Protection Systems and Remedial Action Schemes into these evaluations.

Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee

Answer	No
Document Name	

Comment

Please see response to Question 2.

Likes 0	
Dislikes 0	

Response

Please see the response in question 2.

Douglas Webb on Behalf of: Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Answer	Yes
Document Name	

Comment

No comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

In our interpretation of the proposed changes to the definitions, the intent is that the RC needs to be familiar with the 'functions and limits' of the Protection System and RAS so they can Identify and understand how those systems will impact system reliability and/or if that system reliability is reduced or threatened. Additionally, the operators must include this knowledge into their everyday process of analyzing and operating their portion of the system in reference to the (BES) SOL and IROL. Based on the presentations from the webinar (April 5, 2016), we interpret that the proposed changes are intended to ensure the Analysis Performance under PER-005-2 includes both the Protection System and RAS. If that is the case, we feel that the message may not be conveyed adequately in the mapping document. We suggest adding some footnotes or other language to the document stating why the Requirements are mentioned, however we're not sure that the end goal is sufficiently communicated in order to help the industry understand the proposed changes.

Additionally we suggest the drafting team consider whether the proposed changes to the definitions should be conducted independent of this project. There are already many moving pieces in this project and this only adds more confusion. Technically, there are five proposed Standards associated with this project and all depends on the retirement of PRC-001 and its Requirements. Adding two definitions from the previous TOP/IRO Project warrants its own attention.

Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment. The mapping document explains how the current PRC-001-1.1(ii) (*System Protection Coordination*), Requirements R1, R2, R5, and R6 are addressed by other Transmission Operations and Interconnection Reliability Operations, and Coordination (TOP/IRO) Reliability Standards. This along with the proposed PER-006-1 (*Specific Training for Personnel*) and the revised definitions of Operating Planning Analysis (OPA) and Real-time Assessment (RTA) facilitates the complete retirement of PRC-001-1.1(ii). The mapping document is not intended to explain how an entity will incorporate Protection Systems and Remedial Action Schemes (RAS) into their OPA and RTA evaluations. The systematic approach to training under PER-005-2 (*Operations Personnel Training*) is the process by which the Reliability Coordinator and Transmission Operator will determine what training its personnel will receive on how these Protection Systems and Remedial Action Schemes are integrated into the evaluations. The standard and definitions are proposed together because both are integral to the reliability objectives being maintained with the retirement of PRC-001-1.1(ii). Separating them into two different projects would prevent the project from advancing with the recent approval of PRC-027-1 (*Coordination of Protection Systems for Performance During Faults*) onto a filing with regulators.	
Ben Engelby - ACES Power Marketing - 6	
Answer	Yes
Document Name	
Comment	
The proposed modification of these terms achieves the reliability objective.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bradley Collard - SunPower - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3	
Answer	
Document Name	
Comment	
NA	
Likes 0	

Dislikes 0	
Response	
Rob Collins on Behalf of: Scotty Brown, Southern Indiana Gas and Electric Co., 1, 6, 5, 3	
Answer	
Document Name	
Comment	
Vectren is not registered as a Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
N/A.	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	
Document Name	
Comment	
N/A	

Likes 0	
Dislikes 0	
Response	
N/A.	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
N/A	
Oshani Pathirane on Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3	
Answer	
Document Name	
Comment	

N/A

Likes 0	
Dislikes 0	

Response
N/A

4. Do you agree with the proposed Violation Risk Factor (VRF) and Violation Severity Levels (VSLs) for the proposed PER-006-1 Requirement? If not, please provide a basis for revising the VRF and/or what would improve the clarity of the VSLs.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy does not believe that a VRF rating of Medium is appropriate for this requirement. We feel that a VRF of Low is more suitable based on the risk that the requirement poses to the BES.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment. The drafting team notes the Violation Risk Factor / Violation Severity Level Justification document explains that the Violation Risk Factor of Medium is consistent with the training Requirements in the PER-005-2 (*System Personnel Training*) Reliability Standard, which includes the Balancing Authority, Generator Operator, Reliability Coordinator, and Transmission Operator.	
Douglas Webb on Behalf of: Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1	
Answer	No
Document Name	
Comment	
Kansas City Power and Light Company recommends withdrawal of PER-006-1, making the VRF and VSL moot.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	No
Document Name	
Comment	

Violation Severity Levels (VSL) are based on the number of applicable personnel that the GOp failed to train. While TVA understands that NERC and the SDT assigns more risk to non-compliance to these training requirements than was represented in PRC-001-1.1b, TVA believes the drafted thresholds escalate too aggressively. Also, the VSL for failing to train 4 individuals at a single site should be explicit. Given that the greater of the two thresholds for each VSL will apply to any non-compliance, TVA suggests changes to the drafted thresholds as follows.

- **Lower VSL**: (no change).
- **Moderate VSL**: 2 applicable personnel at a single site; or more than 5% and less than 15% of the total applicable personnel of the GOp.
- **High VSL**: 3 or 4 applicable personnel at a single site; or more than 15% and less than 25% of the total applicable personnel of the GOp.
- **Severe VSL**: 5 or more applicable personnel at a single site; or more than 25% of the total applicable personnel of the GOp.

Likes 0	
Dislikes 0	
Response	

The drafting team thanks you for your comment. The drafting team utilized a combination of percentages and individual personnel thresholds to provide a level of equity between all entities. The proposed Violation Severity Levels (VSL) in the PER-006-1 (*Specific Training for Personnel*) Reliability Standard align with the VSL Guideline published by NERC. The drafting team concluded that the VSLs thresholds did not need to be revised as suggested above.

Chris Scanlon - Exelon - 1, Group Name Exelon Generation	
Answer	No
Document Name	
Comment	

Violation Risk Factor

The Violation Risk Factor (VRF) of Medium related to a failure to provide evidence of training for plant operators does not seem to meet the criteria for a Medium Risk factor unless the lack of that training causes an event to occur. A Medium Risk factor is defined as follows:

"A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. "

It would seem more appropriate for this to be considered a Low Risk factor as a lack of being able to provide evidence of training is administrative and is defined as:

"A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature."

Violation Severity Level

The Violation Severity Levels (VSLs) should be enhanced to be explicit in the minimum elements of the training. If an entity provided any training at all it is conceivable that training (regardless of content) would be considered compliant. Exelon does not believe that is the intent of the SDT. Consider revising the technical basis to provide the minimum expectations for the content of the training and revising the VSL to be more specific to the lack of the training containing those elements.

Likes 0	
Dislikes 0	

Response

The drafting team thanks you for your comment. The drafting team notes the Violation Risk Factor / Violation Severity Level Justification document explains that the Violation Risk Factor of Medium is consistent with the training Requirements in the PER-005-2 (*Operations Personnel Training*) Reliability Standard, which includes the Balancing Authority, Generator Operator, Reliability Coordinator, and Transmission Operator.

The content (i.e., operational functionality) of the training is determined by the entity. If the training is not in place, the violation would be binary (i.e., Severe); therefore, the VSLs are additionally gradated to have multiple levels of non-compliance based on percentage or number of individuals that did not receive training. The proposed VSLs in the PER-006-1 (*Specific Training for Personnel*) Reliability Standard align with the VSL Guideline published by NERC.

Amy Casuscelli on Behalf of: Peter Colussy, Xcel Energy, Inc. , 6

Answer	No
Document Name	

Comment	
The VSL for missing one operator at a facility with a large staff might mean missing less than 5% of the operators while at a small peaking or black start unit missing one operator could be 50% to 100% of the people at the site. We propose that he VSL would make more sense if the criteria for a single facility was a percentage of operators at that site missing training, rather than the number of personnel missing the training.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment. The drafting team utilized a combination of percentages and individual personnel thresholds to provide a level of equity between all entities. The drafting team concluded that the Violation Severity Levels (VSL) thresholds did not need to be revised as suggested above.	
Angela Gaines - Portland General Electric Co. - 3	
Answer	No
Document Name	
Comment	
Although PGE appreciates the flexibility that the Standard Drafting Team wrote into this standard, it is difficult to measure compliance as it is written. The current version of PER-006 does not indicate how the VSL will be used to measure compliance beyond the initial training specified by the implementation plan.	
Likes 0	
Dislikes 0	

Response	
The drafting team thanks you for your comment. The drafting team notes that compliance with the standard is based on the Generator Operator providing training to the applicable personnel. Subsequent to the initial training, the Generator Operator will determine when refresher or additional training is required.	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	No
Document Name	
Comment	
It does not require the Generator Operator (GOP) to perform any verification activities of retention of the training following the training, nor does it address training refreshment. The results of this omission diverges from the structure established in PER-005-2 R1, R2, and R3, and would put the RE examiner in the position of testing all plant operators and assess their abilities to properly assign a VSL. It also follows that the RE examiner would have to be familiar with the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility. This could be a stretch for most examiners, and, at the very least, lengthen the time of preparation for examination.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. Requirement R1 of PER-006-1 (*Specific Training for Personnel*) does not require refreshment and is not intended to align with the systematic approach to training in PER-005-2 (*Operations Personnel Training*). The performance of the requirement is to provide training and not test the plant operator's retention of the training. Content of the operational functionality of the Protection Systems and Remedial Action Schemes (RAS) are the areas of focus and it is not intended for the auditor to question the depth of the content.	

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leo Bernier - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Essential Power, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rob Collins on Behalf of: Scotty Brown, Southern Indiana Gas and Electric Co., 1, 6, 5, 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane on Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3	
Answer	
Document Name	
Comment	
N/A	

Likes 0	
Dislikes 0	

Response
N/A

5. ***Do the PER-006-1, Application Guidelines provide sufficient guidance, basis for approach, and examples to support performance of the Requirement? If not, please provide specific detail that would improve the Application Guidelines.***	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	No
Document Name	
Comment	
It does not require the Generator Operator (GOP) to perform any verification activities of retention of the training following the training, nor does it address training refreshment. The results of this omission diverges from the structure established in PER-005-2 R1, R2, and R3, and would put the RE examiner in the position of testing all plant operators and assess their abilities to properly assign a VSL. It also follows that the RE examiner would have to be familiar with the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility. This could be a stretch for most examiners, and, at the very least, lengthen the time of preparation for examination.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments. Requirement R1 of PER-006-1 (*Specific Training for Personnel*) does not require refreshment and is not intended to align with the systematic approach to training in PER-005-2 (*Operations Personnel Training*). The performance of the requirement is to provide training and not test the plant operator's retention of the training. Content of the operational functionality of the Protection Systems and Remedial Action Schemes (RAS) are the areas of focus and it is not intended for the auditor to question the depth of the content.	
Don Schmit - Nebraska Public Power District - 5	
Answer	No

Document Name	
Comment	

Guidance and Technical Basis Section R1:

- "plant personnel" and "GOP" are used interchangeably throughout this Guidance and Technical Basis section. As identified on the commenting sessions with the drafting team, the drafting team identified that the control function may occur in various "entity configurations". Example given was that a central GOP dispatch center may be the function that controls the generator and not the plant itself. Suggest you change the use of "plant" to "GOP" and/or provide a qualifier for understanding.
- Paragraph 1: Sentence 2 that reads "To accomplish this, **plant personnel responsible for Real-time control and operation of a generating Facility** must understand how Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility". Remove **"and operation",** as this causes confusion as to whom is to be trained. Explanations during commmenting sessions was very confusing on whom this Standard applies. We do understand that there are different functional applications through the utility industry, however it would seem that the use of "Real-time" [a NERC defined term] indeed makes it clear that it is the "first responders" (first responders, a term used by the SDT in clarifying their position on this Standard). Note: remove "and operation" in subsequent paragraphs also.
- Paragraph 1, sentence 2 that reads: "To accomplish this, plant personnel responsible for Real-time control and operation of a generating Facility **must understand** how Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility." Delete **"must understand"** and insert **"must be trained on**". There is no testing associated with this Standard, only training. "must understand" implies a testing measurement function. This change lines up with the Requirment 1.
- Paragraph 2. Sentence that states "A periodicity for training is not specified in Requirement R1 because it is incumbent upon the GOP to ensure its plant personnel that have Real-time control and operation of a generator are trained in order to operate the plant". You are correct a periodocity is not specified and is also not a part of the Standard. The Requirement and its mesurement do not even imply retraining. Only the Guidance and Technical Basis and the RSAW address re-training. Please see the proposed addition in #1 of the 'Additional Comments' at the end of the commenting form for proposed addition to the Requirement 1. In addition the RSAW, in the 'Evidence Requested" section asks the auditor to verify documentation of changes or additions or Protection Systems and RAS during the compliance monitoring period (this RSAW requirement comes from

language in the Guidelines and Technical Basis section). This is not called out in the Standard and should be added to the R1-Mesurements or elsewhere in the Requirment. • Paragraph 2, Second sentence that states "The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service". Delete this sentence as training frequency is already covered in the sentence following the proposed deleted sentence. The two sentences contradict each other. • Paragraph 2 Sentence that states "On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS". The RSAW 'Note to Auditor' section is explicit that Training should be updated for additions and changes. This does not meet the intent of the SDT (as noted in the sentence identified above "the GOP has the flexibility…"). As written this will lead to different audit practices throughout the industry. If the training is not updated, as the current RSAW language is written, this could be a violation in audit application. See #2 of the 'Additional Comments' section at the bottom of this commenting form for proposed RSAW change and in addition the already provided #1 in the 'Additional Comments' section below.	
Likes 0	
Dislikes 0	

Response

The drafting team thanks you for your comment. The drafting team modified the second paragraph of the PER-006-1 (*Specific Training for Personnel*)Guidelines and Technical Basis (Supplemental Material Section of PER-006-1) to eliminate the confusion.

The phrase "and operation" has been deleted as it does not add any additional clarity.

The drafting team revised the Guidelines and Technical Basis to remove "understand" and replaced it with "be trained on how the operational functionality of" for clarity. The rationale box was not changed as it communicates the intent of the standard.

The Guidelines and Technical Basis has been revised to remove the sentence "The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or Remedial Action Scheme (RAS) is placed into service" as noted in the above comment.

The drafting team has proposed to NERC Compliance to remove the sentence "Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies)" from the Reliability Standard Audit Worksheet (RSAW) to address this concern.	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	
Recommend the addition within Guidance and Technical Basis to align with the Section 4.1 of this Standard: **Requirement R1** The Generator Operator (GOP) monitors and controls its generating Facilities in Real-time to maintain reliability. To accomplish this, applicable plant personnel responsible for Real-time control and operation of a generating Facility must understand how Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment. The drafting team inserted the word "applicable" as referenced above to address the comment.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	

Comment	
The Application Guidelines should be revised to preclude the RSAW conflict discussed above, i.e. directly stating that Facility-specific course materials are not obligatory.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment. The drafting team has proposed edits to the Reliability Standard Audit Worksheet (RSAW), a NERC Compliance document, to address the perceived inconsistency between Guidelines and Technical Basis (Supplemental Material section of PER-006-1) and the RSAW.	

Chris Scanlon - Exelon - 1, Group Name Exelon Generation

Answer	No
Document Name	

Comment

Exelon requests that the SDT be more specific regarding the applicable systems that would fall within the scope of PER-006-1. The current draft provides an exclusion for those protective systems which trip breakers serving station auxiliary loads, secondary unit substations or low switchgear transformers and relays protecting other downstream plant electrical distribution system components (even if a trip of these devices might result in a trip of the unit); however it, does not address the following:

1. Protection systems associated with station auxiliary transformers that supply the station and are fed by external power IF the protection system would open breakers that affect the Bulk Electric System (BES) (e.g., the breakers feed into a ring bus). [Note this does not include a transformer fed from a radial line]. Trip of these transformers may or may not trip the unit depending on the plant design.

2. Protection systems associated with unit auxiliary transformers that supply the station and are fed by the generating unit. In this case the trip of the auxiliary transformer would directly trip the generating unit.

Furthermore, the considerations for operational functionality should list the minimum training elements required – not provide the latitude for an auditor or entity to interpret what should be considered.

Likes 0	
Dislikes 0	

Response

The drafting team thanks you for your comment. The drafting team notes that Requirement R1 of PER-006-1 (*Specific Training for Personnel*) only includes the Protection Systems and Remedial Action Schemes (RAS) that "affect the output" (i.e., generator to BES) of the generating Facility and not those systems associated with the unit auxiliary transformer, whether fed locally or remotely. The drafting team feels that entities are most qualified to develop training content for plant personnel. The Guidelines and Technical Basis (Supplemental Material section of PER-006-1) provides a suggested list of elements to consider when training on the operational functionality.

M Lee Thomas - Tennessee Valley Authority - 5

Answer	No
Document Name	

Comment

No "Application Guidelines" were found in the standard. This answer is based on the assumption that the question intended to reference the "Guidelines and Technical Basis."

The second sentence of the second paragraph of the Guidelines and Technical Basis states,

"The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service."

While the interpretation provided here is appreciated, TVA does not agree with the premise of the statement. If the intention of the SDT is to require GOP personnel receive training before a Protection System or RAS is placed into service, then R1 or a sub-requirement should state this explicitly, which would comport with maintaining Reliability of the BES. Further, the next sentence states, "On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e .g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS." The “flexibility” given the GOP in this sentence “concerning new systems” is inconsistent with the previous sentence and creates ambiguity regarding when training for new systems is required. The phrase “ongoing basis” would imply the statement is addressing training after a Protection System or RAS has been placed into service, but the parenthetical “concerning new systems” creates the inconsistency.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment. The Guidelines and Technical Basis (Supplemental Material section of PER-006-1) has been revised to remove the sentence “The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service” as noted in the above comment. The drafting team also modified the subsequent sentence to clarify the intent.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	

Guidance and Technical Basis Section R1:

- “plant personnel” and “GOP” are used interchangeably throughout this Guidance and Technical Basis section. As identified on the commenting sessions with the drafting team, the drafting team identified that the control function may occur in various “entity configurations”. Example given was that a central GOP dispatch center may be the function that controls the generator and not the plant itself. Suggest you change the use of "plant" to "GOP" and/or provide a qualifier for understanding.
- Paragraph 1: Sentence 2 that reads “To accomplish this, **plant personnel responsible for Real-time control and operation of a generating Facility** must understand how Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility". Remove **“and operation”,** as this causes confusion as to whom is to be trained. Explanations during commmenting sessions was very confusing on whom this Standard applies. We do understand that there are different functional applications through the utility industry, however it would seem that the use of “Real-time” [a NERC defined term] indeed makes it clear that it is the “first responders” (first responders, a term used by the SDT in clarifying their position on this Standard). Note: remove “and operation” in subsequent paragraphs also.
- Paragraph 1, sentence 2 that reads: "To accomplish this, plant personnel responsible for Real-time control and operation of a generating Facility **must understand** how Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility." Delete **“must understand”** and insert **“must be trained on”**. There is no testing associated with this Standard, only training. “must understand” implies a testing measurement function. This change lines up with the Requirment 1.
- Paragraph 2. Sentence that states "A periodicity for training is not specified in Requirement R1 because it is incumbent upon the GOP to ensure its plant personnel that have Real-time control and operation of a generator are trained in order to operate the plant" . You are correct a periodocity is not specified and is also not a part of the Standard. The Requirement and its mesurement do not even imply retraining. Only the Guidance and Technical Basis and the RSAW address re-training. Please see the proposed addition in #1 of the ‘Additional Comments’ at the end of the commenting form for proposed addition to the Requirement 1. In addition the RSAW, in the ‘Evidence Requested” section asks the auditor to verify documentation of changes or additions or Protection Systems and RAS during the compliance monitoring period (this RSAW requirement comes from language in the Guidelines and Technical Basis section). This is not called out in the Standard and should be added to the R1-Mesurements or elsewhere in the Requirment.

- Paragraph 2, Second sentence that states “The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service". Delete this sentence as training frequency is already covered in the sentence following the proposed deleted sentence. The two sentences contradict each other.
- Paragraph 2 Sentence that states “On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS". The RSAW ‘Note to Auditor’ section is explicit that Training should be updated for additions and changes. This does not meet the intent of the SDT (as noted in the sentence identified above "the GOP has the flexibility…"). As written this will lead to different audit practices throughout the industry. If the training is not updated, as the current RSAW language is written, this could be a violation in audit application. See #2 of the ‘Additional Comments’ section at the bottom of this commenting form for proposed RSAW change and in addition the already provided #1 in the ‘Additional Comments’ section below.

Likes 0	
Dislikes 0	

Response

The drafting team thanks you for your comment. The drafting team modified the second paragraph of the Guidelines and Technical Basis (Supplemental Material section of PER-006-1) to eliminate the confusion.

The phrase “and operation” has been deleted as it does not add any additional clarity.

The drafting team thanks you for your suggestions. Requirement R1 of PER-006-1 (*Specific Training for Personnel*) does not require refresher training and is not intended to align with the systematic approach to training in PER-005-2 (*Operations Personnel Training*).

The Guidelines and Technical Basis has been revised to remove the sentence “The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service” as noted in the above comment.

The drafting team has proposed edits to the Reliability Standard Audit Worksheet (RSAW), a NERC Compliance document, to address the inconsistency between PER-006-1, Requirement R1 and the RSAW.

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
The application guidelines lack a true description of who the standard applies to. The NERC Functional Model defines Generator Operator as: "The functional entity that operates generating unit(s) and performs the functions of supplying energy and reliability related services." Question arises does this apply only to registered entities of the "Generator Operator" regardless of their voltage level, generation capacity and point of interconnection with the BES?	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment. The PER-006-1 (*Specific Training for Personnel*) Reliability Standard is applicable to registered Generator Operators regardless of voltage, generating capacity, or point of interconnection. The standard further applies to Facilities that meet the definition of "Bulk Electric System" (BES).	

Douglas Webb on Behalf of: Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1	
Answer	No
Document Name	
Comment	
Kansas City Power and Light Company recommends withdrawal of PER-006-1 and its associated guidelines, making the Application Guidelines moot.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Ben Engelby - ACES Power Marketing - 6	
Answer	No
Document Name	
Comment	
We recommend that the drafting team clarify in the Application Guidelines for Requirement R1 that one-time training is required for applicable plant personnel. There is nothing in the language of the requirement to require additional, continuing, and/or retraining to occur. The RSAW has made an assumption that retraining is required, which needs to be corrected to align with the requirement. If the SDT does intend for additional, continuing and/or retraining, this would be a substantive change and would require another posting of the revised requirement for industry comment and ballot.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment. The drafting team has proposed edits to the Reliability Standard Audit Worksheet (RSAW), a NERC Compliance document, to address the inconsistency between PER-006-1 (*Specific Training for Personnel*), Requirement R1 and the RSAW.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	Yes

Document Name	PER_006_1_System_Protection_Draft_1_FE Comments.docx
Comment	

FirstEnergy Comments

PER-006-1 – Specific Training for Personnel

Draft 1 – Ballot Ending April 25, 2016

The following comments are offered to the NERC Standard Draft Team (SDT) to support why FirstEnergy (FE) has voted NEGATIVE on the 1st Draft version of PER-006-1. Our comments also offered suggested revisions in order for FE to support the standard.

1. The 2nd paragraph of the Guidelines and Technical Basis section includes the statement *"The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service."* FE recommends the text be deleted as it is inconsistent with the R1 requirement as presented in Draft 1. This statement adds additional obligations not within the standard. Nowhere in the requirement language is this "dictated" or required. Additionally, this could raise questions to when training is needed for revised Protection Systems that may only include minor setting changes for coordination improvement but no material change in the intended outcome of the protection scheme.

2. The Guidelines and Technical Basis section offers 6 bullet listed items/topics for consideration for training intended to cover the "operational functionality" of a Protection System or RAS. FE offers a re-write of this area to place greater emphasis on the first and last bulleted items which we believe are the most appropriate areas to cover with generation plant operators. The other four items are more technical and design/engineering details that should be more clearly optional.

3. As a minor note, FE suggests adding the word "Operations" in the standard title to read "Specific Training for Operations Personnel". Doing so would better compliment the PER-005-2 standard which is titled "Operations Personnel Training" which focuses on a systematic approach to training for reliability related tasks.

The attached file includes an excerpt of the Draft 1 PER-006-1 standard with suggested red-line edits to the Guidelines and Technical Basis section.

If the SDT wishes to discuss FE's comments please contact Doug Hohlbaugh, Manager, Reliability Compliance at 330-384-4698.

Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment. The PER-006-1 (*Specific Training for Personnel*) Guidelines and Technical Basis (see Supplemental Material section of PER-006-1) has been revised to remove the sentence "The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service" as noted in the above comment. The drafting team notes that the considerations of operational functionality are examples and are provided for guidance. The drafting team avoided the term "operations" in the title because PER-005-2 (*Operations Personnel Training*) already uses this to define the personnel and that PER-006-1 could potentially be used for other specific training requirements.	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli on Behalf of: Peter Colussy, Xcel Energy, Inc. , 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rob Collins on Behalf of: Scotty Brown, Southern Indiana Gas and Electric Co., 1, 6, 5, 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	Yes
Document Name	
Comment	
Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Essential Power, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Oshani Pathirane on Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

6. ***Do you agree with implementation period (i.e., 12 months) of the proposed PER-006-1 Reliability Standard and the proposed definition modifications of OPA and RTA based on the considerations listed in the Implementation Plan? If not, please provide a justification for changing the proposed implementation periods.***	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy does not believe that an Implementation Plan of 12 months is appropriate for the amount of work that would be involved for larger utilities with numerous generating facilities. An entity would need time to develop additional training materials (in addition to what is already in use for compliance with PRC-001-1.1(ii)) with specificity for each of its generating facilities, and then administer said training to all applicable operators within a 12 month timeframe. A significant amount of time would need to be allotted to accomplish develop and distribute the additional required tasks, much more than the proposed 12 months.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment and has increased the implementation period to 24 months.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

Comments: As currently worded, the modification of OPA and RTA may require entities to collect and include a large, voluminous set of data in their RTAs and OPAs. This would require entities to make modeling and Energy Management System changes to accommodate all the relay information, which would require time to upgrade technology. Taking into account budgeting, design, and implementation, the time necessary to upgrade this technology could run 24 to 36 months.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment and has increased the implementation period to 24 months.	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	No
Document Name	
Comment	
A period of 12 months is too short to generate operator lists, identify the "Set of Protection Systems and Remedial Action Schemes" and to create and roll out a new training program. Suggest at least a 24 month period.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment and has increased the implementation period to 24 months. The drafting team has also proposed the removal of the "Set of Protection Systems and Remedial Action Schemes from the evidence section of the RSAW, a NERC Compliance document.	

Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	No
Document Name	
Comment	

PSEG thanks the drafting team for its efforts and appreciates having the opportunity to comment on the proposed OPA and RTA definitions. PSEG is in general agreement with the intent of the proposed OPA and RTA definitions as it applies to the inclusion of Protection Systems and RASs in evaluations and assessments (that would be conducted by operations personnel). The wording of the current version of each definition states that OPA evaluations and RTA assessments "…shall reflect applicable inputs including… known Protection System and Remedial Action Scheme status or degradation, functions, and limits…". PSEG agrees that OPAs and RTAs should include the status or degradation of known protection systems and RASs. Additionally, we believe that inclusion of the "functions and limits" of RASs in OPAs and RTAs would improve reliability. However, it is requested that the requirement to include the "functions and limits" of [all] known Protection Systems be removed from the OPA and RTA definitions. As they are currently written, the definitions imply that the (operations) personnel who perform OPAs and RTAs would require detailed information regarding the settings for all protection systems (or schemes) that are within their scope of operations in order to complete OPAs and RTAs. PSEG does not believe that this level of detail regarding [all] protection systems is necessary in OPAs and RTAs in order to maintain reliability of the BES. PSEG therefore proposes that the definitions be revised as follows:

Operational Planning Analysis (OPA)

An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to**:** load forecasts; generation output levels; Interchange; known Protection System status or degradation; and **Remedial Action Scheme** status or degradation**, functions, and limits**; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Real-time Assessment (RTA)

An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load**;** generation output levels**;** known

Protection System status or degradation; and **Remedial Action Scheme** status or degradation**, functions, and limits;** Transmission outages**;** generator outages**;** Interchange**;** Facility Ratings**;** and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) PSEG, Segment(s) 5, 6, 1, 3, 3/10/2016	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment and notes that Reliability Standards IRO-010-2 (*Reliability Coordinator Data Specification and Collection*) for the Reliability Coordinator and TOP-003-3 (*Operational Reliability Data*) for the Transmission Operator, Requirements R1, Parts 1.2 are one method in which Protection Systems and Remedial Action Schemes become inputs into the Operational Planning Analysis and Real-time Assessment. However, the Reliability Coordinator and Transmission Operator may have additional Protection Systems and Remedial Action Schemes included as inputs and those too would be in purview. The limits and functions pertain to these Protection Systems and Remedial Action Schemes within its documented data specification; therefore, the suggested modification would further narrow the intent and does not address the reliability objective in PRC-001-1.1(ii) (*System Protection Coordination*), Requirement R1 that includes Protection Systems.	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
In alignment with the recent training related implementation plans, 24 months is more realistic to incorporate new requirements into existing training programs.	
Likes 0	

Dislikes 0	
Response	
The drafting team thanks you for your comment and has increased the implementation period to 24 months.	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	No
Document Name	
Comment	

PSEG thanks the drafting team for its efforts and appreciates having the opportunity to comment on the proposed OPA and RTA definitions. PSEG is in general agreement with the intent of the proposed OPA and RTA definitions as it applies to the inclusion of Protection Systems and RASs in evaluations and assessments (that would be conducted by operations personnel). The wording of the current version of each definition states that OPA evaluations and RTA assessments "…shall reflect applicable inputs including… known Protection System and Remedial Action Scheme status or degradation, functions, and limits…". PSEG agrees that OPAs and RTAs should include the status or degradation of known protection systems and RASs. Additionally, we believe that inclusion of the "functions and limits" of RASs in OPAs and RTAs would improve reliability. However, it is requested that the requirement to include the "functions and limits" of [all] known Protection Systems be removed from the OPA and RTA definitions. As they are currently written, the definitions imply that the (operations) personnel who perform OPAs and RTAs would require detailed information regarding the settings for all protection systems (or schemes) that are within their scope of operations in order to complete OPAs and RTAs. PSEG does not believe that this level of detail regarding [all] protection systems is necessary in OPAs and RTAs in order to maintain reliability of the BES. PSEG therefore proposes that the definitions be revised as follows:

Operational Planning Analysis (OPA)

An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to**:** load forecasts; generation output levels; Interchange; known Protection System status or degradation; and **Remedial Action Scheme** status or degradation**, functions,**

and limits; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Real-time Assessment (RTA)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load**;** generation output levels**;** known Protection System status or degradation; and **Remedial Action Scheme** status or degradation**, functions, and limits;** Transmission outages**;** generator outages**;** Interchange**;** Facility Ratings**;** and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)	
Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
The drafting team thanks you for your comment and notes that Reliability Standards IRO-010-2 (*Reliability Coordinator Data Specification and Collection*) for the Reliability Coordinator and TOP-003-3 (*Operational Reliability Data*) for the Transmission Operator, Requirements R1, Parts 1.2 are one method in which Protection Systems and Remedial Action Schemes become inputs into the Operational Planning Analysis and Real-time Assessment. However, the Reliability Coordinator and Transmission Operator may have additional Protection Systems and Remedial Action Schemes included as inputs and those too would be in purview. The limits and functions pertain to these Protection Systems and Remedial Action Schemes within its documented data specification; therefore, the suggested modification would further narrow the intent and does not address the reliability objective in PRC-001-1.1(ii) (*System Protection Coordination*), Requirement R1 that includes Protection Systems.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

An implementation plan of 12 months is insufficient, as it may not allow larger entities adequate time to improve the existing training program under PRC-001 R1. This shortened duration may force large entities to continue utilizing PRC-001 training processes for PER-006-1, which may not meet the auditor's intent. Instead, AEP recommends that a 4 year phased implementation period for the Standard be incorporated as follows: specific training of personnel would consist of 40% within 12 months, 60% within 24 months, 80% within 36 months, and 100% within 48 months following the effective date of the Standard.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment and has increased the implementation period to 24 months.	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb on Behalf of: Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1	

Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Essential Power, LLC - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rob Collins on Behalf of: Scotty Brown, Southern Indiana Gas and Electric Co., 1, 6, 5, 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli on Behalf of: Peter Colussy, Xcel Energy, Inc. , 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Fontenot - Bryan Texas Utilities - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Oshani Pathirane on Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

7. Are you aware of any conflicts between the proposed PER-006-1 Reliability Standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If so, please identify the conflict here.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP is not aware of any potential conflicts between the proposed PER-006-1 Reliability Standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Douglas Webb on Behalf of: Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1	
Answer	No
Document Name	
Comment	
No comments.	
Likes 0	

Dislikes 0	
Response	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Angela Gaines - Portland General Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli on Behalf of: Peter Colussy, Xcel Energy, Inc. , 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rob Collins on Behalf of: Scotty Brown, Southern Indiana Gas and Electric Co., 1, 6, 5, 3	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Generation	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

M Lee Thomas - Tennessee Valley Authority - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Essential Power, LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Oshani Pathirane on Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Answer	
Document Name	

Comment
N/A

Likes 0	
Dislikes 0	

Response

8. Are you aware of the need for a regional variance or business practice that should be considered with this project? If so, please identify it here.	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb on Behalf of: Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1	
Answer	No
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	

Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP is not aware of any potential need for a regional variance or business practice that should be considered with this project.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gerry Adamski - Essential Power, LLC - 5

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Herring - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No NextEra	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Generation	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Venona Greaff - Oxy - Occidental Chemical - 7, Group Name Oxy	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Tim Kucey - PSEG - PSEG Fossil LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Lisembee - Southern Indiana Gas and Electric Co. - 6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Rob Collins on Behalf of: Scotty Brown, Southern Indiana Gas and Electric Co., 1, 6, 5, 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli on Behalf of: Peter Colussy, Xcel Energy, Inc. , 6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Catrina Martin - Utility System Efficiencies, Inc. (USE) - 5	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Oshani Pathirane on Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3	
Answer	Yes
Document Name	
Comment	
Within the province of Ontario, many Ontario Market Rules published by Ontario's Independent Electricity System Operator (IESO) contain requirements that mandate adequate knowledge of system operating staff. Hence, in Ontario, the IESO Market Rules already encompass many of the requirements in this standard for Generator Operators. Similarly, other ISOs may also have pre-defined requirements for operators within their jurisdictions to hold their system operating staff accountable for prior to issuing a transmission or generating license.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Minh Ngo - City of Garland - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

9. *If you have any other comments not previously mentioned above, please provide them here:*

John Fontenot - Bryan Texas Utilities - 1,5

Answer	
Document Name	

Comment

na

Likes 0	
Dislikes 0	

Response

William Hutchison - Southern Illinois Power Cooperative - 1

Answer	
Document Name	

Comment

In agreement with comments submitted by ACES.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Please see the responses to the comments provided by ACES.	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	
Document Name	
Comment	
Reclamation supports the drafting team's effort to move the GOP Protection System training requirement to a Personnel Performance, Training, and Qualification (PER) standard. Reclamation suggests that in the future, PER-006 could be revised to include other one-off GOP training requirements, like the minimum of two hours of GOP blackstart training required every two calendar years in EOP-005 R17. Reclamation appreciates the drafting team's industry outreach and approach to relying on the existing PER-005-2 Systematic Approach to Training standard to replace PRC-001 R1 for BAs, RCs, TOPs, and GOP centrally located dispatch centers, rather than creating duplicative requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your suggestion, comment, and support.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

AEP supports the overall efforts and direction of the project team. Our negative vote on the standard is driven solely by our objections to the implementation plan, as expressed in our response to Question #6.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment and has increased the implementation period to 24 months.	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	
Document Name	
Comment	
PER-006-1; Top of Page 4 says; "When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material section of the standard." Is this the most updated NERC template, from other standards we have reviewed, we thought that the Rationale boxes were going to stay with the Requirements after approved. Please advise.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The rationale boxes are moved to the "Supplemental Material" section of the standard. In some cases, the rational information for a previous version of the standard may be removed by the drafting team revising said standard.	
Angela Gaines - Portland General Electric Co. - 3	

Answer	
Document Name	
Comment	

- The RSAW requests documentation of Protection System and RAS changes, but there is no mention of how the auditors will use this list to measure compliance if there is no frequency for training. As the standard is written, there is no timeframe for training operators on these changes.
- Without any requirement in this standard for the TOP to notify the GOP of changes to the Protection Systems and RAS, PGE sees a gap in the compliance monitoring for this when the TOP for several plants is a different entity.

Likes 0	
Dislikes 0	

Response

The drafting team thanks you for your comments. The drafting team has proposed edits to the Reliability Standard Audit Worksheet (RSAW), a NERC Compliance document, to address the inconsistency between Requirement R1 and the RSAW.

The drafting team notes that how the Generator Operator becomes informed of Protection System and Remedial Action Scheme changes are not within scope of this project.

Don Schmit - Nebraska Public Power District - 5

Answer	
Document Name	
Comment	

ADDITIONAL COMMENTS:

#1: Suggessted sub-requirement for this Standard under R1

R1.1: the Generator Operator shall determine when its plant personnel need to receive additional training, such as new systems, replacements, technology and operational functionality, of Protection Systems and RAS.

Add the following to Measurement 1: Documentation of changes or additions during the compliance monitoring period that effect the output of the generating facility(ies).

#2:

Within the proposed PER-006-1 RSAW in relation to R1, there is a note to the auditor (page 5), which states that "Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes that affect the output of the Facility".

The Guidelines and Technical Basis within the Standard, under R1, (page 9 of 10, second paragraph) states "On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS".

To maintain the intent of the drafting team we propose that the *note to the auditor* reflect the drafting teams intent from the Guidelines and Technical Basis section. We recommend the following wording that reflects the SDT's intent:

NOTE TO AUDITOR: Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes that affect the output of the Facility; however the Generator Operator has the flexibility to determine when its personnel need to receive additional training (new systems, replacements, technology, and operational functionality) on the operational functionality of Protection Systems and RAS.

Likes 0	
Dislikes 0	

Response

The drafting team thanks you for your suggestions. Requirement R1 does not require refresher training and allows the Generator Operator to determine if or when to perform refresher or additional training.

The drafting team has proposed edits to the RSAW, a NERC Compliance document, to address the inconsistency between Requirement R1 and the RSAW. The Guidelines and Technical Basis has been revised to remove the sentence “The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service” as noted in the above comment.	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
Within the proposed PER-006-1 RSAW in relation to R1, there is a note to the auditor (page 5), which states that “Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes that affect the output of the Facility”. The Guidelines and Technical Basis within the Standard, under R1, (page 9 of 10, second paragraph) states “On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS”. The NSRF wants to maintain this intent of the drafting team and we propose that the *note to the auditor* reflect the drafting teams intent from the Guidelines and Technical Basis section. The NSRF recommends the following wording that reflects the SDT’s intent. NOTE TO AUDITOR: Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes that affect the output of the Facility; **however the Generator Operator has the flexibility to determine when its personnel need to receive additional training (new systems, replacements, technology, and operational functionality) on the operational functionality of Protection Systems and RAS.** (Bold is additional recommended text.)	
Likes 0	
Dislikes 0	
Response	

The drafting team has proposed to NERC Compliance to remove the sentence "Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies)" from the RSAW to address this concern.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	

Even though the PER-006-1 draft standard aids in ensuring that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the BES, ReliabilityFirst believes the requirement fall short as there is no periodicity of training noted in the requirement. ReliabilityFirst provides the following comments for consideration:

1. Requirement R1

    i. Even though the "Guidelines and Technical Basis" states "The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service.", the actual requirement has no periodicity requirements. If the true intent of the SDT is to have the GOP personnel receive training before the Protection Systems or RAS is placed into service, ReliabilityFirst believes this language should be added to the Requirement. ReliabilityFirst also seeks clarification on the timing of when new personal are required to receive this training (e.g., is it required prior to going on shift for the first time). Also is it the expectation of the SDT that existing personal are required to receive this training by the time this standard becomes effective? If this is the case, the SDT may want to consider including this in the Implementation Plan. ReliabilityFirst offers the following for consideration:

        a. Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1., on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies) it operates, [either prior to new personnel going on shift for the first time or prior to Protection Systems or RAS placed into service].

Likes 0	

Dislikes 0	
Response	
The drafting team thanks you for your comments. Requirement R1 does not require refresher training and is not intended to align with the systematic approach to training in PER-005 (*Operations Personnel Training*). The performance of the requirement is to provide training and not test the plant operator's retention of the training. Content of the operational functionality of the Protection Systems and Remedial Action Schemes are the areas of focus and it is not intended for the auditor to question the depth of the content. The Guidelines and Technical Basis has been revised to remove the sentence "The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service" as noted in the above comment.	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern Company is in agreement with the draft standard PER-006-1 and revisions to the definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	

Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Council- Standards Review Committee (SRC).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to the comments submitted by ISO/RTO Council- Standards Review Committee (SRC).	
William Temple on Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Answer	
Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Council- Standards Review Committee (SRC).	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comment. Please see the response to the comments submitted by ISO/RTO Council- Standards Review Committee (SRC).	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	

Answer	
Document Name	
Comment	
Thank you to the SDT for breaking this out and creating a new PER standard. SRP supports this action and appreicates the efforts taken to make this happen.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	
Document Name	
Comment	
With regard to the structure of PER-006-1: In this case, a new standard, containing a single requirement, is proposed to require GOPs train on “operational functionality specific to Protection Systems and Remedial Action Schemes and their effects on generating Facilities.” This is a deviation from past practice whereby prior GOP training requirements, such as that for system restoration from Blackstart Resources (EOP-005-2, R17) and communication (COM-002-4, R3), have been included with the subject matter material as opposed to a Personnel Performance, Training and Qualifications (PER) standard. APS recommends NERC consider (as part of a future effort and assuming PER-006-1 is adopted) whether it would make sense to migrate all GOP training requirements under PER-006-1. Alternatively, this training requirement could be placed within an appropriate Protection and Control (PRC) standard, although with the retirement of PRC-001-1(ii), there does not appear to be an ideal location for this requirement.	

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The drafting team feels that the PER (*Personnel Performance, Training, and Qualifications*) family of Reliability Standards is the appropriate place for the requirement.

Chris Scanlon - Exelon - 1, Group Name Exelon Generation

Answer	
Document Name	

Comment

The SDT needs to ensure that the RSAW aligns with PER-006-1 intent. Currently the draft RSAW for PER-006-1 specifies the following evidence requested to demonstrate compliance.

"Documentation of changes or additions during the compliance monitoring period to Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies)."

This requested evidence does not align with the current version of PER-006-1. Per the "Guidelines and Technical Basis" the "periodicity for training is not specified in Requirement R1 because it is incumbent upon the GOP to ensure its plant personnel … … are trained in order to operate the plant." And further states that "the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.)"

Although it would seem entirely reasonable for a functional change to warrant additional training, the evidence request in the RSAW could be broadly interpreted that ALL changes, regardless of impact or non-impact to the functionality of the Protection System, would require training prior to implementation. This is an unnecessary burden on the GOP and in Exelon's opinion was not the intent of the SDT.

Likes 0	

Dislikes 0	
Response	
The drafting team thanks you for your comment and has proposed edits to the Reliability Standard Audit Workshop (RSAW), a NERC Compliance document, to address the perceived inconsistency between Guidelines and Technical Basis and the RSAW.	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	
Document Name	
Comment	

The purpose of the standard as drafted in section A.3, "topics essential to Reliability to perform or support," is worded awkwardly. The topics are not directly essential to Reliability. Performance and support of Real-Time operations should be the subject of the topics. The standard should apply to training on topics regarding only those Real-time operations that are essential to Reliability of the BES. Accordingly, TVA suggests the purpose should state, "To ensure that personnel are trained on specific topics regarding performance or support of Real-time operations essential to reliability of the Bulk Electric System."

The RSAW requires the following evidence:

- Identification of responsible personnel
- Identification of the set of Protection Systems and Remedial Action Schemes that affect the output of the generating facility(ies).
- Evidence that the identified personnel completed the training
- Documentation of changes or additions to the identified Protection Systems and Remedial Action Schemes

This expectation is presented in both the “Evidence Requested,” and in the “Assessment Approach” sections of the RSAW. However, this seems to introduce new requirements and measurements in the RSAW beyond what is stated in the draft standard. The measurement of compliance as stated in the standard is simply that, “Each Generator Operator shall have available for inspection, evidence that the applicable personnel completed training.” TVA acknowledges that maintaining a list of applicable personnel is essential to meeting the stated measure. However, the RSAW expectation to provide a list of Protection Systems and Remedial Action Schemes, as well as documentation of changes or additions to these systems, expands the scope of required evidence to include the adequacy of the training content, which is not addressed in either in the Requirement or the Measure as drafted. At first blush, these new requirements appear to be supported by the statement in the "Guidelines and Technical Basis" section of the standard which states, "The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service." However, it is immediately refuted by the next sentence which states, "On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e .g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS." TVA respectfully requests that the drafted standard (Measure and Guidelines/Basis) and the RSAW be aligned to remove the ambiguity, 1) between statements in the Guidelines and Technical Basis as previously described, and 2) between the RSAW and the standard Measure. The RSAW should be revised to remove expectations for maintaining documentation of the set of Protection Systems and Remedial Action Schemes and changes or additions to these systems and schemes.	
Likes 0	
Dislikes 0	
Response	

The drafting team thanks you for your comments and believes the purpose statement in its current form provides sufficient clarity. The purpose statement is meant to be general enough to allow future requirements to be incorporated into PER-006-1 (*Specific Training for Personnel*). The drafting team has proposed edits to the RSAW, a NERC Compliance document, to address the inconsistency between Measure M1 and the RSAW. The Guidelines and Technical Basis has been revised to remove the sentence “The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service” as noted in the above comment.

Jamison Cawley - Nebraska Public Power District - 1

Answer	
Document Name	

Comment

ADDITIONAL COMMENTS:

#1: Suggessted sub-requirement for this Standard under R1

R1.1: the Generator Operator shall determine when its plant personnel need to receive additional training, such as new systems, replacements, technology and operational functionality, of Protection Systems and RAS.

Add the following to Measurement 1: Documentation of changes or additions during the compliance monitoring period that effect the output of the generating facility(ies).

#2:

Within the proposed PER-006-1 RSAW in relation to R1, there is a note to the auditor (page 5), which states that “Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes that affect the output of the Facility”.

The Guidelines and Technical Basis within the Standard, under R1, (page 9 of 10, second paragraph) states “On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and operational functionality changes, etc.) on the operational functionality of Protection Systems and RAS”.

To maintain the intent of the drafting team we propose that the *note to the auditor* reflect the drafting teams intent from the Guidelines and Technical Basis section. We recommend the following wording that reflects the SDT’s intent:

NOTE TO AUDITOR: Training should be updated to include changes or additions to Protection Systems and Remedial Action Schemes that affect the output of the Facility; however the Generator Operator has the flexibility to determine when its personnel need to receive additional training (new systems, replacements, technology, and operational functionality) on the operational functionality of Protection Systems and RAS.

Likes 0	
Dislikes 0	

Response

The drafting team thanks you for your suggestions. PER-006-1 (*Specific Training for Personnel*) Requirement R1 does not require refresher training and allows the Generator Operator to determine if or when to perform refresher or additional training.

The drafting team has proposed edits to the RSAW, a NERC Compliance document, to address the inconsistency between Requirement R1 and the RSAW.

The Guidelines and Technical Basis has been revised to remove the sentence “The structure of the requirement dictates that the GOP personnel receive training before the Protection Systems or RAS is placed into service” as noted in the above comment.

Douglas Webb on Behalf of: Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Answer	
Document Name	

Comment

No other comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	

Comment	
PacifiCorp believes that a new standard, PER-006, would be superfluous to PER-005. An entirely new standard only increases compliance documentation burden without any incremental increase in reliability to the BES. The proposed changes could be made in a new version of PER-005-2, identified as PER-005-3. Both PER-005-2 and the current PER-006 address the same issue. As standards are rewritten, training requirements need to be consolidated not only within the PER section but within the same standard. This would provide consistent approach and reduce the possibility of conflicting terms and applications.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments and believes that PER-006-1 (Specific Training for Personnel) provides clarity over PRC-001-1.1(ii) (System Protection Coordination), Requirement R1 to identify the appropriate personnel who must receive training (be familiar with). Withdrawing PER-006-1 and its associated Guidelines would result in a reliability gap in the absence of PRC-001-1.1(ii). The Generator Operator personnel at a centrally located dispatch center is addressed by PER-005-2 (Operations Personnel Training) and does not address plant personnel as expected by PER-006-1. The PER-005-2 standard is based on a systematic approach to training and would not ensure that training on Protection Systems and Remedial Action Schemes is provided for plant personnel, which are not applicable to PER-005-2. A technical conference held by the drafting team revealed that stakeholders did not want the burden of a systematic approach to training to be applied to plant personnel.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE noticed there is no explanation for the term “calendar year” in the Evidence Retention section of PER-006-1. Footnote #3 of Table 1-1 in PRC-005-6 explains how to apply the term calendar year in PRC-005-6. Is the intent that the term calendar year in PER-006-1 be applied the same as it is applied in PRC-005-6?	
Likes 0	
Dislikes 0	
Response	
The term “calendar year” is understood as January 1 to December 31.	
Ben Engelby - ACES Power Marketing - 6	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Vine - California ISO - 2, Group Name ISO/RTO Council Standards Review Committee	
Answer	

Document Name	
Comment	
SRC would like to recognize the willingness of the project team to move away from the initial TOP-009 proposed standard based on the majority comments received from the industry. In addition, the numerous outreach efforts by the project team was instrumental in understanding the industry comments and arriving at the right solution at the end. This is a good example of how the existing iterative process will yield the right results when given the opportunity. Thank you.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	
Document Name	
Comment	
According to the accompanying RSAW "Documentation of changes or additions during the compliance monitoring period to Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies)" will be requested as evidence for PER-006-1 R1. Tri-State believes there is no corresponding requirement in the current draft of PRC-006-1 that suggests this information is necessary. If it was the SDT's intentions that there be additional training prior to implementing any changes to the Protection Systems or RAS that affect the output of the Facility, then there should be a requirement that explicitly states that. Tri-State suggests that the SDT create a requirement or sub-requirement to require entities to provide new or additional training to its plant personnel prior to the change in the Protection Systems and RAS being made, so that they are aware of the operational functionality.	

We heard in one of the Q&A sessions that the operators at a dispatch center could be included if they have direct control, in Real-time, of an unmanned plant via remote access capabilities. While we don't disagree with this inclusion, the applicability section does not convey this. We would suggest that the SDT include this scenario within the applicability section.	
Likes 0	
Dislikes 0	
Response	
The drafting team thanks you for your comments and has proposed edits to the RSAW, a NERC Compliance document, to address the inconsistency between PER-006-1 (*Specific Training for Personnel*) Requirement R1 and the RSAW. The drafting team notes that operators at a dispatch center are already covered under PER-005-2 (*Operations Personnel Training*) as "dispatch personnel at a centrally located dispatch center" and are not applicable to PER-006-1.	
Oshani Pathirane on Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

End of Report

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

The System Protection Coordination (Phase 2) Standard Drafting Team (SPCP2SDT) is addressing Requirements R1, R2, R5, and R6 of PRC-001-1.1(ii). The PER-006-1 Reliability Standard addresses the Generator Operator (GOP) that is applicable to Requirement R1 of PRC-001-1.1(ii).

Requirements R1, R2, and R5 applicable to the GOP are proposed for retirement as described below.

1. The PER-006-1, Requirement R1, applicable to the GOP, is proposing to replace PRC-001-1.1(ii), Requirement R1 to address the reliability objective of ensuring GOP plant operating personnel are "familiar with the purpose and limitations of Protection Systems." The standard PER-005-2 already addresses centrally located dispatch center personnel.
2. The Personnel Performance, Training, and Qualifications (PER) set of Reliability Standards and Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards address the reliability objective of PRC-001-1.1(ii), Requirements R2 and R5.

Requirements R1 and R6 applicable to the Balancing Authority (BA) and Requirements R1, R2, R5, and R6 applicable to the Transmission Operator (TOP) are proposed for retirement on the following basis.

1. The TOP/IRO sets of Reliability Standards address the reliability objective of these requirements.
2. The revisions to the definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA), that the TOP and the Reliability Coordinator perform, address the reliability objective of integrating the function and limits of Protection Systems and Remedial Action Schemes (RAS) into their OPA and RTA.

See the Project 2007-06.2 mapping document for further explanation on how the PER and TOP/IRO sets Reliability Standards and the revision of the two definitions address the reliability objectives of PRC-001-1.1(ii), Requirements R1, R2, R5, and R6 for the BA and TOP. The PRC-027-1 (*Coordination of Protection System Performance During Faults*) Reliability Standard addresses Requirements R3 and R4 of PRC-001-1.1(ii).

The PER-006-1 Reliability Standard and revisions to the definitions of OPA and RTA are being posted for an initial 45-day formal comment period with a concurrent initial ballot to be held in the last ten days of the comment period.

Completed Actions	Date
Standard Authorization Request (SAR) posted for comment	June 11 – July 10, 2007
SAR approved by Standards Committee (SC)	August 13, 2007
SC authorized posting of TOP-009-1	July 28, 2015
Draft 1, TOP-009-1, posted for a 45-day formal comment period	July 29 – September 11, 2015
Draft 1, TOP-009-1, concurrent/parallel initial ballot in the last ten days of the comment period	September 2-11, 2015
Draft 2, TOP-009-1, posted for a 45-day formal comment period	October 6 – November 19, 2015
Draft 2, TOP-009-1, concurrent/parallel additional ballot in the last ten days of the comment period	November 10-19, 2015
Draft 2, TOP-009-1 withdrawn from development at SDT meeting	February 9, 2016
SC authorized posting of PER-006-1	March 9, 2016

Anticipated Actions	Date
Draft 1, PER-006-1, 45-day formal comment period with initial ballot	March 10 – April 25, 2016
10-day final ballot	May 2016
NERC Board (Board) adoption	August 2016

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material section of the standard.

A. Introduction

1. **Title:** **Specific Training for Personnel**
2. **Number:** **PER-006-1**
3. **Purpose:** To ensure that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the Bulk Electric System.
4. **Applicability:**

    4.1. Functional Entities:

    4.1.1. Generator Operator that has:

    4.1.1.1. Plant personnel who are responsible for the Real-time control of a generator and receive Operating Instruction(s) from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center.

5. **Effective Date:** See Implementation Plan for Project 2007-06.2.

B. Requirements and Measures

Rationale for Requirement R1: Protection Systems and Remedial Action Schemes (RAS) are an integral part of reliable Bulk Electric System (BES) operation. This requirement addresses the reliability objective of ensuring that Generator Operator (GOP) plant operating personnel understand the operational functionality of Protection Systems and RAS and their effects on generating Facilities.

R1. Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies) it operates. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M1. Each Generator Operator shall have available for inspection, evidence that the applicable personnel completed training. This evidence may be documents such as training records showing successful completion of training that includes training materials, the name of the person, and date of training.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:**

   "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

   1.2. **Evidence Retention:**

   The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   - The Generator Operator shall keep data or evidence of Requirement R1 for the current year and three previous calendar years.

   1.3. **Compliance Monitoring and Enforcement Program**

   As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • one applicable personnel at a single Facility, or • 5% or less of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • two applicable personnel at a single Facility, or • more than 5% and less than or equal to 10% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • three applicable personnel at a single Facility, or • more than 10% and less than or equal to 15% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • five or more applicable personnel at a single Facility, or • more than 15% of the total applicable personnel of the Generator Operator. **OR** The Generator Operator failed to provide training as described in Requirement R1 to its applicable personnel.

D. Regional Variances

None.

E. Associated Documents

Project 2007-06.2 Implementation Plan[1]

[1] http://www.nerc.com/pa/Stand/Project200706_2SystemProtectionCoordinationDL/Project_2007_06_2_Imp_Plan_Draft_1_2016_03_10_Clean.pdf

Version History

Version	Date	Action	Change Tracking
1		Adopted by the NERC Board of Trustees	New standard developed under Project 2007-06.2

Guidelines and Technical Basis

Requirement R1

The Generator Operator (GOP) monitors and controls its generating Facilities in Real-time to maintain reliability. To accomplish this, applicable plant personnel responsible for Real-time control of a generating Facility must be trained on how the operational functionality of Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility. Although, training does not have to be Facility-specific, the standard applies to plant operating personnel associated with the specific Facility to which they have Real-time control. This does not include plant personnel not responsible for Real-time control (e.g., fuel or coal handlers, electricians, machinists, or maintenance staff).

A periodicity for training is not specified in Requirement R1 because the GOP must ensure its plant personnel who have Real-time control of a generator are trained. The Generator Operator must also ensure it provides applicable training that results from changes to the operational functionality of the Protection Systems and Remedial Action Schemes that affect the output of the generation Facility(ies).

The phrase "operational functionality" focuses the training on how Protection Systems operate and prevent possible damage to Elements. It also addresses how RAS detects pre-determined BES conditions and automatically takes corrective actions.

Considerations for operational functionality may include, but are not limited to the following:

- Purpose of protective relays and RAS
- Zones of protection
- Protection communication systems (e.g., line current differential, direct transfer trip, etc.)
- Voltage and current inputs
- Station dc supply associated with protective functions
- Resulting actions – tripping/closing of breakers; tripping of a generator step-up (GSU) transformer; or generator ramping/tripping control functions

Requirement R1 focuses on the operational functionality of Protection Systems and Remedial Action Schemes specific to the generating plant and not the Bulk Electric System.

This requirement focuses on those systems that are related to the electrical output of the generator. Protective systems which trip breakers serving station auxiliary loads (e.g., such as pumps, fans, or fuel handling equipment) are not included in the scope of this training. Furthermore, protection of secondary unit substation (SUS) or low voltage switchgear transformers and relays protecting other downstream plant electrical distribution system components are not in the scope of this training, even if a trip of these devices might eventually result in a trip of the generating unit.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

The System Protection Coordination (Phase 2) Standard Drafting Team (SPCP2SDT) is addressing Requirements R1, R2, R5, and R6 of PRC-001-1.1(ii). The PER-006-1 Reliability Standard addresses the Generator Operator (GOP) that is applicable to Requirement R1 of PRC-001-1.1(ii).

Requirements R1, R2, and R5 applicable to the GOP are proposed for retirement as described below.

1. The PER-006-1, Requirement R1, applicable to the GOP, is proposing to replace PRC-001-1.1(ii), Requirement R1 to address the reliability objective of ~~being~~ensuring GOP plant operating personnel are "familiar with the purpose and limitations of Protection Systems~~" for the GOP's plant operator personnel.~~." The standard PER-005-2 already addresses centrally located dispatch center personnel.
2. The Personnel Performance, Training, and Qualifications (PER) set of Reliability Standards and Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards address the reliability objective of PRC-001-1.1(ii), Requirements R2 and R5.

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2. The revisions to the definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA), that the TOP and the Reliability Coordinator perform, address the reliability objective of integrating the function and limits of Protection Systems and Remedial Action Schemes (RAS) into their OPA and RTA.

See the Project 2007-06.2 mapping document for further explanation on how the PER and TOP/IRO sets Reliability Standards and the revision of the two definitions address the reliability objectives of PRC-001-1.1(ii), Requirements R1, R2, R5, and R6 for the BA and TOP. The PRC-027-1 (*Coordination of Protection System Performance During Faults*) Reliability Standard addresses Requirements R3 and R4 of PRC-001-1.1(ii).

The PER-006-1 Reliability Standard and revisions to the definitions of OPA and RTA are being posted for an initial 45-day formal comment period with a concurrent initial ballot to be held in the last ten days of the comment period.

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A. Introduction

1. **Title:** **Specific Training for Personnel**
2. **Number:** **PER-006-1**
3. **Purpose:** To ensure that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the Bulk Electric System.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Generator Operator that has:
       - **4.1.1.1.** Plant personnel who are responsible for the Real-time control of a generator and receive Operating Instruction(s) from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center.
5. **Effective Date:** See Implementation Plan for Project 2007-06.2.

B. Requirements and Measures

Rationale for Requirement R1: Protection Systems and Remedial Action Schemes (RAS) are an integral part of reliable Bulk Electric System (BES) operation. This requirement addresses the reliability objective of ensuring that ~~the~~ Generator Operator (GOP) plant operating personnel understand the operational functionality of Protection Systems and RAS and their effects on generating Facilities.

R1. Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies) it operates. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M1. Each Generator Operator shall have available for inspection, evidence that the applicable personnel completed training. This evidence may be documents such as training records showing successful completion of training that includes training materials, the name of the person, and date of training.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Generator Operator shall keep data or evidence of Requirement R1 for the current year and three previous calendar years.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • one applicable personnel at a single Facility, or • 5% or less of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • two applicable personnel at a single Facility, or • more than 5% and less than or equal to 10% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • three applicable personnel at a single Facility, or • more than 10% and less than or equal to 15% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • five or more applicable personnel at a single Facility, or • more than 15% of the total applicable personnel of the Generator Operator. **OR** The Generator Operator failed to provide training as described in Requirement R1 to its applicable personnel.

D. Regional Variances

None.

E. Associated Documents

Project 2007-06.2 Implementation Plan[1]

[1] http://www.nerc.com/pa/Stand/Project200706_2SystemProtectionCoordinationDL/Project_2007_06_2_Imp_Plan_Draft_1_2016_03_10_Clean.pdf

Version History

Version	Date	Action	Change Tracking
1		Adopted by the NERC Board of Trustees	New standard developed under Project 2007-06.2

Guidelines and Technical Basis

Requirement R1

The Generator Operator (GOP) monitors and controls its generating Facilities in Real-time to maintain reliability. To accomplish this, applicable plant personnel responsible for Real-time control ~~and operation~~ of a generating Facility must ~~understand~~be trained on how the operational functionality of Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility. ~~This standard requires GOPs to train their plant personnel on these issues. The standard only~~Although, training does not have to be Facility-specific, the standard applies to plant operating personnel associated with the specific Facility to which they have Real-time control. This does not include ~~other~~ plant personnel not responsible for Real-time control (e.g., fuel or coal handlers, electricians, machinists, or maintenance staff).

A periodicity for training is not specified in Requirement R1 because ~~it is incumbent upon~~ the GOP ~~to~~must ensure its plant personnel ~~that~~who have Real-time control ~~and operation~~ of a generator are trained~~ in order to operate the plant.~~. The ~~structure of the requirement dictates that the GOP personnel receive~~Generator Operator must also ensure it provides applicable training ~~before the Protection Systems or RAS is placed into service. On an ongoing basis, the GOP has the flexibility to determine when its plant personnel need to receive additional training (e.g., concerning new systems, replacements, technology and~~ that results from changes to the operational functionality ~~changes, etc.) on the operational functionality~~of the Protection Systems and Remedial Action Schemes that affect the output of ~~Protection Systems and RAS.~~the generation Facility(ies).

The phrase “operational functionality” focuses the training on how Protection Systems operate and prevent possible damage to Elements. It also addresses how RAS detects pre-determined BES conditions and automatically takes corrective actions.

Considerations for operational functionality may include, but ~~is~~are not limited to the following:

- Purpose of protective relays and RAS
- Zones of protection
- Protection communication systems (e.g., line current differential, direct transfer trip, etc.)
- Voltage and current inputs
- Station dc supply associated with protective functions
- Resulting actions – tripping/closing of breakers; tripping of a generator step-up (GSU) transformer; or generator ramping/tripping control functions

Requirement R1 focuses on the operational functionality of Protection Systems and Remedial Action Schemes specific to the generating plant and not the Bulk Electric System.

This requirement focuses on those systems that are related to the electrical output of the generator. Protective systems which trip breakers serving station auxiliary loads (e.g., such as pumps, fans, or fuel handling equipment) are not included in the scope of this training. Furthermore, protection of secondary unit substation (SUS) or low voltage switchgear transformers and relays protecting other downstream plant electrical distribution system components are not in the scope of this training, even if a trip of these devices might eventually result in a trip of the generating unit.

~~A. Introduction~~

~~**1. Title: System Protection Coordination**~~

~~**2. Number:** PRC-001-1.1(ii)~~

~~**3. Purpose:**~~

~~To ensure system protection is coordinated among operating entities.~~

~~**4. Applicability**~~

~~**4.1.** Balancing Authorities~~

~~**4.2.** Transmission Operators~~

~~**4.3.** Generator Operators~~

~~**5. Effective Date:**~~

~~See the Implementation Plan for PRC-001-1.1(ii).~~

ORANGE TEXT – Retirements of R1, R2, R5, and R6 occurring under Project 2007-06.2.

RED TEXT – Retirements of R3 and R4 occurring under Project 2007-06.

~~B. Requirements~~

~~**R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.~~

~~**R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:~~

~~**R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.~~

~~**R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.~~

~~**R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.~~

~~**R3.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.~~

- ~~Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.~~

~~**R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.~~

~~**R4.** Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.~~

~~**R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:~~

~~**R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.~~

~~**R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.~~

~~**R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.~~

~~C. Measures~~

~~**M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.~~

~~**M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)~~

~~**M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)~~

~~D. Compliance~~

~~1. Compliance Monitoring Process~~

~~1.1. Compliance Monitoring Responsibility~~

~~Regional Reliability Organizations shall be responsible for compliance monitoring.~~

~~1.2. Compliance Monitoring and Reset Time Frame~~

~~One or more of the following methods will be used to assess compliance:~~

- ~~Self-certification (Conducted annually with submission according to schedule.)~~
- ~~Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)~~
- ~~Periodic Audit (Conducted once every three years according to schedule.)~~
- ~~Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance.~~

~~1.3. Data Retention~~

~~Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.~~

~~Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.~~

~~If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.~~

~~Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,~~

~~The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.~~

~~1.4. Additional Compliance Information~~

~~None.~~

~~2. Levels of Non-Compliance for Generator Operators:~~

~~**2.1. Level 1:** Not applicable.~~

~~**2.2. Level 2**: Not applicable.~~

~~**2.3. Level 3**: Not applicable.~~

~~**2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.~~

~~3. Levels of Non-Compliance for Transmission Operators:~~

~~**3.1. Level 1:** Not applicable.~~

~~**3.2. Level 2**: Not applicable.~~

~~**3.3. Level 3**: Not applicable.~~

~~**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**3.4.1** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.~~

~~**3.4.2** Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.~~

~~**4. Levels of Non-Compliance for Balancing Authorities:**~~

~~**4.1. Level 1:** Not applicable.~~

~~**4.2. Level 2**: Not applicable.~~

~~**4.3. Level 3**: Not applicable.~~

~~**4.4. Level 4:** Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.~~

~~E. Regional Differences~~

~~None identified.~~

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~0~~	~~April 1, 2005~~	~~Effective Date~~	~~New~~
~~0~~	~~August 8, 2005~~	~~Removed "Proposed" from Effective Date~~	~~Errata~~
~~0~~	~~August 25, 2005~~	~~Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0~~	~~Errata~~
~~1~~	~~November 1, 2006~~	~~Adopted by the NERC Board of Trustees~~	~~Revised~~
~~1.1~~	~~April 11, 2012~~	~~Errata adopted by the Standards Committee; (Capitalized "Protection System" in accordance with Implementation Plan for Project 2007-17 approval of revised definition of "Protection System")~~	~~Errata associated with Project 2007-17~~
~~1.1~~	~~September 9, 2013~~	~~Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.~~	

~~1.1(i)~~	~~November 13, 2014~~	~~Adopted by the NERC Board of Trustees~~	~~Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS~~
~~1.1(ii)~~	~~February 12, 2015~~	~~Adopted by the NERC Board of Trustees~~	~~Standard revised in Project 2014-01:~~ ~~Applicability revised to clarify application of requirements to BES dispersed power producing resources~~
~~2~~	~~May 9, 2012~~	~~Adopted by Board of Trustees~~	~~Deleted Requirements R2, R5, and R6.~~
~~1.1(ii)~~	~~May 29, 2015~~	~~FERC Letter Order in Docket No. RD15-3-000 approving PRC-001-1.1(ii)~~	~~Modifications to adjust the applicability to owners of dispersed generation resources.~~

~~Rationale:~~

~~During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.~~

~~Rationale for the Applicability Exclusion in Requirement R3.1~~

~~Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the~~

~~transmission protective systems, as this coordination would not provide reliability benefits to the BES.~~

Proposed Definitions

Project 2007-06.2 Phase 2 of System Protection Coordination

Introduction

The following definitions are proposed for revision under the Project 2007-06.2 – Phase 2 of System Protection Coordination. The definitions of Operational Planning Analysis (OPA) and Real-time Assessment (RTA) are used in the Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards.[1] To address the reliability objective of PRC-001-1.1(ii) – *System Protection Coordination*, Requirement R1 to be familiar with the limitations of Protection System schemes, the two definitions are being modified to include the phrase "…functions, and limitations…" to ensure the Transmission Operator (TOP), consider the functions and limitations of Protection Systems and Remedial Action Schemes in their evaluations. The PRC-001-1(ii) standard is not applicable to the Reliability Coordinator (RC), however, the modifications to the definitions affect this entity. The reliability objective is addressed by revising the definitions to require the RC and the TOP to integrate the functions and limitations (i.e., purpose and limitations) into its OPA and RTA to ensure that the Bulk Electric System is operated within System Operating Limits and Interconnection Reliability Operating Limits.

Proposed Definitions

This section includes the two proposed modified definitions that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval, in accordance with the associated implementation plan. Terms that are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard PER-006-1 – *Specific Training for Personnel* in order to completely retire PRC-001-1.1(ii).

These two terms are not found within the proposed PER-006-1 standard, but are an integral part of the basis for the retirement of PRC-001-1.1(ii), Requirement R1. There are two significant revisions:

1. An administrative update to replace "Special Protection System" to "Remedial Action Scheme."
2. The addition of the phrase "…functions, and limitations…" to address the reliability objective of PRC-001-1.1(ii), Requirement R1 for the applicable TOP that must integrate the "functions and limitations" into these evaluations. The proposed definition revision also has an effect on the RC that is not applicable to PRC-001-1.1(ii). The bold text in the definitions below accentuate the proposed revisions.

[1] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order No. 817, 153 FERC ¶ 61,178 (2015).

Operational Planning Analysis (OPA)

An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to**:** load forecasts; generation output levels; Interchange; known Protection System and **Remedial Action Scheme** status or degradation**, functions, and limitations**; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Real-time Assessment (RTA)

An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load**;** generation output levels**;** known Protection System and **Remedial Action Scheme** status or degradation**, functions, and limitations;** Transmission outages**;** generator outages**;** Interchange**;** Facility Ratings**;** and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Proposed Definitions

Project 2007-06.2 Phase 2 of System Protection Coordination

Introduction

The following definitions are proposed for revision under the Project 2007-06.2 – Phase 2 of System Protection Coordination. The definitions of Operational Planning Analysis (OPA) and Real-time Assessment (RTA) are used in the Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards.[1] To address the reliability objective of PRC-001-1.1(ii) – *System Protection ~~System~~ Coordination*, Requirement R1 to be familiar with the ~~limits~~limitations of Protection System schemes, the two definitions are being modified to include the phrase "…functions, and ~~limits~~limitations…" to ensure the Transmission Operator (TOP), ~~and Reliability Coordinator (RC) that is not applicable to PRC-001-1.1(ii),~~ consider the functions and ~~limits~~limitations of Protection Systems and Remedial Action Schemes in their evaluations. The PRC-001-1(ii) standard is not applicable to the Reliability Coordinator (RC), however, the modifications to the definitions affect this entity. The reliability objective is addressed by revising the definitions to require the RC and the TOP to integrate the functions and ~~limits~~limitations (i.e., purpose and limitations) into its OPA and RTA to ensure that the Bulk Electric System is operated within System Operating Limits and Interconnection Reliability Operating Limits.

Proposed Definitions

This section includes the two ~~modified terms used in the Reliability Standards and requirements below~~proposed modified definitions that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval~~.~~, in accordance with the associated implementation plan. Terms that are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard PER-006-1 – *Specific Training for Personnel* in order to completely retire PRC-001-1.1(ii).

~~**Term(s):**~~

These two terms are not found within the proposed PER-006-1 standard, but are an integral part of the basis for the retirement of PRC-001-1.1(ii), Requirement R1. There are two significant revisions~~.~~:

1. An administrative update to replace "Special Protection System" to "Remedial Action Scheme."
2. The addition of the phrase "…functions, and ~~limits~~limitations…" to address the reliability objective of PRC-001-1.1(ii), Requirement R1 for the applicable TOP that must integrate the "functions and ~~limits~~limitations" into these evaluations. The proposed definition revision also has an effect on the RC that is not applicable to PRC-001-1.1(ii). The bold text in the definitions below accentuate the proposed revisions.

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[1] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order No. 817, 153 FERC ¶ 61,178 (2015).

Operational Planning Analysis (OPA)
An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to**:** load forecasts; generation output levels; Interchange; known Protection System and **Remedial Action Scheme** status or degradation**, functions, and** ~~limits~~limitations; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Real-time Assessment (RTA)
An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load**;** generation output levels**;** known Protection System and **Remedial Action Scheme** status or degradation**, functions, and** ~~limits~~limitations**;** Transmission outages**;** generator outages**;** Interchange**;** Facility Ratings**;** and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Implementation Plan

Project 2007-06.2 Phase 2 of System Protection Coordination

Requested Approvals

- PER-006-1 – Specific Training for Personnel
- Definition of "Operational Planning Analysis"
- Definition of "Real-time Assessment"

Requested Retirements

- PRC-001-1.1(ii) – System Protection Coordination[1]

Prerequisite Approvals

- PRC-027-1 – Coordination of Protection Systems for Performance During Faults

Applicable Entities

- Generator Operator (applicable to PER-006-1 only)
- Reliability Coordinator (applicable to definitions only)
- Transmission Operator (applicable to definitions only)

General Considerations

There are a number of factors that influence the determination of the implementation period for the proposed standard and revised definitions. The following factors address the Balancing Authority, Generator Operator, and Transmission Operator:

1. The effort and resources by the Generator Operator to provide training to plant personnel to address the operational functionality of Protection Systems and Remedial Action Schemes at individual generating Facilities in PER-006-1 that the Generator Operator may not have been addressing under PRC-001-1.1(ii), Requirement R1.

2. Maintain consistency with the Implementation Plan of the approved Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards[2] that are applicable to the Balancing Authority and Transmission Operator. This

[1] The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of both proposed Reliability Standards PRC-027-1 and PER-006-1, and the proposed definitions for "Operational Planning Analysis" and "Real-time Assessment." NERC is proposing the complete retirement of PRC-001-1.1(ii) in the implementation plans associated with both PRC-027-1 and PER-006-1. The Project 2007-06 System Protection Coordination Mapping Document shows how PRC-027-1 addresses requirements R3 and R4 of PRC-001-1.1(ii). The remaining requirements of PRC-001-1.1(ii) – Requirements R1, R2, R5, and R6 are proposed for retirement in Project 2007-6.2 Phase 2 of System Protection Coordination (see the Mapping Document for Project 2007-06.2 Phase 2 of System Protection Coordination).

[2] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order No. 817, 153 FERC ¶ 61,178 (2015).

project explains how the retirement of PRC-001-1.1(ii) Requirements R1, R2, R5, and R6 are addressed by the TOP/IRO sets standards.

3. Maintaining consistency with the Implementation Plan of the approved TOP/IRO standards[3] that are applicable to the Balancing Authority and Transmission Operator in the application of the revised definitions of "Operational Planning Analysis" and "Real-time Assessment" (effective January 1, 2017) in the *NERC Glossary of Term Used in NERC Reliability Standards*. See the Project 2007-06.2 Mapping Document for additional details.

4. The amount of time needed by the Transmission Operator in PRC-001-1.1(ii), Requirement R1 and Reliability Coordinator (not applicable to PRC-001-1.1(ii)) to train on Protection Systems and Remedial Action Schemes in order to be capable of integrating their functions and limits into their Operational Planning Analysis and Real-time Assessment.

Effective Dates

PER-006-1 – Specific Training for Personnel

Where approval by an applicable governmental authority is required, Reliability Standard PER-006-1 – Specific Training for Personnel shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Operational Planning Analysis and Real-time Assessment

Where approval by an applicable governmental authority is required, the definitions "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA) in the NERC Glossary of Terms Used in NERC Reliability Standards shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving the definition, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirements

PRC-001-1.1(ii) – System Protection Coordination

Requirement R1

PRC-001-1.1(ii) – System Protection Coordination, Requirement R1 shall be retired immediately prior to the effective date of PER-006-1 (*Specific Training for Personnel*) and the revised definitions of

[3] Id.

“Operational Planning Analysis” (OPA) and “Real-time Assessment” (RTA), or as otherwise provided for by an applicable governmental authority.

Requirement R2, R5, and R6

PRC-001-1.1(ii) – System Protection Coordination, Requirement R2, R5, and R6 shall be retired at midnight of March 31, 2017, or as otherwise provided for by an applicable governmental authority.

Requirements R3 and R4

See Project 2007-06 System Protection Coordination Implementation Plan.[4]

Retirement of Existing Standards and Definitions

The currently-approved definitions of “Operations Planning Analysis” and “Real-time Assessment” shall be retired immediately prior to the effective date of the revised definitions of “Operational Planning Analysis” (OPA) and “Real-time Assessment” (RTA), or as otherwise provided for by an applicable governmental authority.

[4] http://www.nerc.com/pa/Stand/Project%20200706%20System%20Protection%20Coordination%20DL/Implementation_Plan_PRC-027-1_clean_10012015.pdf

Implementation Plan

Project 2007-06.2 Phase 2 of System Protection Coordination

Requested Approvals

- PER-006-1 – Specific Training for Personnel
- Definition of "Operational Planning Analysis"
- Definition of "Real-time Assessment"

Requested Retirements

- PRC-001-1.1(ii) – System Protection Coordination[1]

Prerequisite Approvals

- PRC-027-1 – Coordination of Protection Systems for Performance During Faults

Applicable Entities

- Generator Operator (applicable to PER-006-1 only)
- Reliability Coordinator (applicable to definitions only)
- Transmission Operator (applicable to definitions only)

General Considerations

There are a number of factors that influence the determination of the implementation period for the proposed standard and revised definitions. The following factors address the Balancing Authority, Generator Operator, and Transmission Operator:

1. The effort and resources by the Generator Operator to provide training to plant personnel to address the operational functionality of Protection Systems and Remedial Action Schemes at individual generating Facilities in PER-006-1 that the Generator Operator may not have been addressing under PRC-001-1.1(ii), Requirement R1.

2. Maintain consistency with the Implementation Plan of the approved Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards[2] that are applicable to the Balancing Authority and Transmission Operator. This

[1] The complete retirement of PRC-001-1.1(ii) is contingent upon the approval of both proposed Reliability Standards PRC-027-1 and PER-006-1, and the proposed definitions for "Operational Planning Analysis" and "Real-time Assessment." NERC is proposing the complete retirement of PRC-001-1.1(ii) in the implementation plans associated with both PRC-027-1 and PER-006-1. The Project 2007-06 System Protection Coordination Mapping Document shows how PRC-027-1 addresses requirements R3 and R4 of PRC-001-1.1(ii). The remaining requirements of PRC-001-1.1(ii) – Requirements R1, R2, R5, and R6 are proposed for retirement in Project 2007-6.2 Phase 2 of System Protection Coordination (see the Mapping Document for Project 2007-06.2 Phase 2 of System Protection Coordination).

[2] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order No. 817, 153 FERC ¶ 61,178 (2015).

project explains how the retirement of PRC-001-1.1(ii) Requirements R1, R2, R5, and R6 are addressed by the TOP/IRO sets standards.

3. Maintaining consistency with the Implementation Plan of the approved TOP/IRO standards[3] that are applicable to the Balancing Authority and Transmission Operator in the application of the revised definitions of "Operational Planning Analysis" and "Real-time Assessment" (effective January 1, 2017) in the *NERC Glossary of Term Used in NERC Reliability Standards*. See the Project 2007-06.2 Mapping Document for additional details.

4. The amount of time needed by the Transmission Operator in PRC-001-1.1(ii), Requirement R1 and Reliability Coordinator (not applicable to PRC-001-1.1(ii)) to train on Protection Systems and Remedial Action Schemes in order to be capable of integrating their functions and limits into their Operational Planning Analysis and Real-time Assessment.

Effective Dates

PER-006-1 – Specific Training for Personnel

Where approval by an applicable governmental authority is required, Reliability Standard PER-006-1 – Specific Training for Personnel shall become effective on the first day of the first calendar quarter that is ~~twelve (12~~twenty-four (24) months after the effective date ~~that~~of the applicable governmental authority's order approving the standard~~ is approved ~~, or as otherwise provided by ~~an~~the applicable governmental authority~~ or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. ~~.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is ~~twelve (12~~twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Operational Planning Analysis and Real-time Assessment

~~The~~Where approval by an applicable governmental authority is required, the definitions "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA) in the NERC Glossary of Terms Used in NERC Reliability Standards shall become effective on the first day of the first calendar quarter that is ~~twelve (12~~twenty-four (24) months after the effective date ~~that~~of the ~~definitions are approved by an~~ applicable governmental ~~authority~~authority's order approving the definition, or as otherwise provided for ~~in a jurisdiction where approval ~~by ~~an~~the applicable governmental authority~~ is required for a definition to go into effect. ~~.

Where approval by an applicable governmental authority is not required, the definitions shall become effective on the first day of the first calendar quarter that is ~~twelve (12~~twenty-four (24) months after the date the definitions are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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[3] Id.

Retirements

PRC-001-1.1(ii) – System Protection Coordination

Requirement R1

PRC-001-1.1(ii) – System Protection Coordination, Requirement R1 shall be retired ~~at midnight of the day~~ immediately prior to the effective date of PER-006-1 (*Specific Training for Personnel*) and the revised definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA), or as otherwise provided for by an applicable governmental authority.

Requirement R2, R5, and R6

PRC-001-1.1(ii) – System Protection Coordination, Requirement R2, R5, and R6 shall be retired at midnight of March 31, 2017, or as otherwise provided for by an applicable governmental authority.

Requirements R3 and R4

See Project 2007-06 System Protection Coordination Implementation Plan.[4]

Retirement of Existing Standards and Definitions

The currently-approved definitions of "Operations Planning Analysis" and "Real-time Assessment" shall be retired ~~at midnight of the day~~ immediately prior to the effective date of the revised definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA), or as otherwise provided for by an applicable governmental authority.

[4] http://www.nerc.com/pa/Stand/Project%20200706%20System%20Protection%20Coordination%20DL/Implementation_Plan_PRC-027-1_clean_10012015.pdf

Mapping Document

Project 2007-06.2 Phase 2 of System Protection Coordination

Revisions or Retirements to Already Approved Standards

This mapping document explains how each of the existing Requirements (R1, R2, R5, and R6) of PRC-001-1.1(ii) (*System Protection Coordination*)[1] are being revised or retired. If a requirement is being proposed for revision, the revised, new, and/or supporting requirement(s) will be identified in the center column. If a requirement is being proposed for retirement, the center column will describe the proposed action and any requirement(s) used to support the action. Revisions and retirements will be accompanied by an explanation or justification listed in the right column. Capitalized terms, unless otherwise noted, are those found in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary").[2] References to regulatory directives are specifically related to Order No. 693 ("Order").[3] Standards or definitions listed as "existing" are enforceable and those listed as "approved" have been adopted by the NERC Board of Trustees and approved by the Federal Energy Regulatory Commission ("FERC"). Check the NERC website for effective dates. The functional entities discussed in the mapping document are the Balancing Authority (BA), Generator Operator (GOP), Planning Coordinator (PC), Reliability Coordinator (RC), Transmission Operator (TOP), and Transmission Planner (TP). The term "TOP/IRO" refers to the Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) sets of Reliability Standards that were filed under NERC Project 2014-03 – Revisions to TOP and IRO Standards[4] and approved by FERC.[5] The explanation herein assumes that the term, "Special Protection

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[1] Federal Energy Regulatory Commission (FERC) approved PRC-001-1.1(ii), effective May 29, 2015.
[2] *Glossary of Terms Used in NERC Reliability Standards*. December 7, 2015. (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).
[3] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[4] http://www.nerc.com/pa/Stand/Pages/Project-2014-03-Revisions-to-TOP-and-IRO-Standards.aspx
[5] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order 817, 153 FERC ¶ 61,178 (November 19, 2015).

System"[6] (SPS) will be replaced by the term "Remedial Action Scheme"[7] (RAS). In the referenced Reliability Standards herein the term SPS may be replaced by RAS; therefore, the term RAS will be used in the "Comments" column throughout.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing)[8,9] **R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall be	PRC-001-1.1(ii), Requirement R1 is proposed for retirement.	**Introduction** The reliability objective of PRC-001-1.1(ii), Requirement R1 is to ensure that the BA,

[6] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Special Protection System is defined as "[a]n automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme."

[7] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), the proposed definition of Remedial Action Scheme is defined as "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as: Meet requirements identified in the NERC Reliability Standards; Maintain Bulk Electric System (BES) stability; Maintain acceptable BES voltages; Maintain acceptable BES power flows; Limit the impact of Cascading or extreme events." See definition for additional information on the definition of RAS.

[8] Order No. 693 at P 1418. "Protection and Control systems (PRC) on Bulk-Power System elements are an integral part of reliable grid operation. Protection systems are designed to detect and isolate faulty elements on a system, thereby limiting the severity and spread of system disturbances, and preventing possible damage to protected elements. The function, settings and limitations of a protection system are critical in establishing SOLs and IROLs. The PRC Reliability Standards apply to transmission operators, transmission owners, generator operators, generator owners, distribution providers and regional reliability organizations and cover a wide range of topics related to the protection and control of power systems."

[9] Order No. 693 at P 1435. "Protection systems on Bulk-Power System elements are an integral part of reliable operations. They are designed to detect and isolate faulty elements on a power system, thereby limiting the severity and spread of disturbances and preventing possible damage to protected elements. If a protection system can no longer perform as designed because of a failure of its relays, system reliability is reduced or threatened. In deriving SOLs and IROLs, moreover, the functions, settings, and limitations of protection systems are recognized and integrated. Systems are only reliable when protection systems perform as designed. This is what PRC-001-1 means in linking a reduction in system reliability with a protection relay failure or other equipment failure."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
familiar with the purpose and limitations of Protection System schemes applied in its area. **Operational Planning Analysis (Approved)** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages;	Being "familiar with the purpose and limitations of Protection System schemes" will be clarified as (1) being "familiar with their purpose," and (2) being "familiar with their limitations" as follows: • The phrase "Protection systems schemes" maps to the NERC Glossary terms of Protection Systems and Remedial Action Schemes. • Being "familiar with the purpose" is addresses by existing and proposed training standards. • Being "familiar with the limitations" together with the clarification found in Order No. 693 at P 1418 and P 1435 along with the revised	GOP, and TOP are "familiar with the purpose and limitations of Protection System[12] schemes applied in its area." The reliability objective of the phrase "Protection System schemes" in PRC-001-1.1(ii), Requirement R1 is also intended to include RAS. The functions and limitations of a Protection Systems and RAS are critical in establishing System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL) such that the Bulk Electric System[13] (BES) is operated within these limits. The following explains how being familiar with the purpose and limitations of Protection Systems and RAS will be addressed according to issue beginning with

[12] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Protection System is defined as:
"Protection System -

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."

[13] See Glossary of Terms Used in NERC Reliability Standards (updated December 7, 2015).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Real-time Assessment (Approved)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)	definitions of NERC Glossary defined terms of Operational Planning Analysis and Real-time Assessment address the reliability objective of PRC-001-1.1(ii), Requirement R1 as explained in the Comments column to the right. **PER-006-1 (New)** **4.** Applicability: **4.1.** Functional Entities: **4.1.1.** Generator Operator that have: **4.1.1.1.** Plant personnel who are responsible for the Real-time control of a generator and receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center. This does not include personnel at a centrally located dispatch center.	"familiarity with their limitations" and then "familiarity with their purpose." **Familiar with their limitations** When the BA, GOP, and TOP are familiar with the limitations of Protection Systems and RAS, the entities are able to operate the BES in such a manner that Protection Systems and RAS will be operated within their limits and be able to detect and isolate faulty Elements, thereby, limiting the severity and spread of system disturbances, and preventing possible damage to protected Elements. When the GOP is familiar with the operational functionality of Protection Systems and RAS by being trained on how Protection Systems operate and prevent possible damage to Elements, the GOP is capable of operating to its full capability within its area, meaning the output of its generation Facilities. When the BA is familiar with the limitations of Protection Systems and RAS, it is capable

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	R1. Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies) it operates. **PER-003-1 (Existing)** **R1.** Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate: **1.1.** Areas of Competency **1.1.1.** Resource and demand balancing **1.1.2.** Transmission operations **1.1.3.** Emergency preparedness and operations	of maintaining generation, Load, and Interchange balance. The BA ensures that RAS in its area are enabled when needed for system reliability. When the TOP is familiar with limitations of Protection Systems and RAS, it will be capable of identifying when system reliability is reduced or threatened. In operating to established SOLs and IROLs, it is important that the functions and limitations of Protection Systems and RAS are recognized and integrated by the TOP into operating the BES reliably. The BES is only reliable when Protection Systems and RAS perform within their limitations. **Familiarity with the Purpose** Familiarity with the purpose of Protection Systems and RAS is achieved through training, as explained below, according to each applicable entity (BA, GOP, and TOP) in PRC-001-1.1(ii) and the RC that is not applicable to this standard, but has been

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	1.1.4. System operations **1.1.5.** Protection and control **1.1.6.** Voltage and reactive **1.1.7.** Interchange scheduling and coordination **1.1.8.** Interconnection reliability operations and coordination **R2.** Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates: **2.1.** Areas of Competency **2.1.1.** Transmission operations **2.1.2.** Emergency preparedness and operations **2.1.3.** System operations **2.1.4.** Protection and control	included to address a potential gap in reliability. **Familiarity with the Purpose (GOP)** For the GOP, the Reliability Standard PER-006-1 (*Specific Training for Personnel*) proposes to replace PRC-001-1.1(ii), Requirement R1. The PER-006-1 standard identifies applicable GOP personnel that are responsible for the Real-time control of a generator and that receive Operating Instructions from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center. This applicability removes ambiguity over which personnel of the GOP are intended to be familiar with the purpose Protection Systems and RAS. Centrally located personnel are not included here because they are addressed by PER-005-2 (*Operations Personnel Training*). Personnel at centrally located dispatch centers will receive company-specific Protection System and RAS training, if identified, as a reliability-

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	2.1.5. Voltage and reactive **2.2.** Certificates • Reliability Operator • Balancing, Interchange and Transmission Operator • Transmission Operator **R3.** Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificate: **3.1.** Areas of Competency **3.1.1.** Resources and demand balancing **3.1.2.** Emergency preparedness and operations **3.1.3.** System operations **3.1.4.** Interchange scheduling and coordination	related task via the PER-005-2, Requirement R6. Here the GOP must use "…a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1. of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations." Being trained using a systematic approach on the purpose (i.e., functions, including limitations) Protection Systems and RAS will enable the GOP centrally located dispatch personnel to ensure reliable operation of its Facilities on the BES. The phrase "…purpose and limitations…" in PRC-001-1-1(ii), Requirement R1 is addressed in the proposed Requirement R1 through the use of "operational functionality." The phrase "operational functionality" as described in the PER-006-1 – Supplemental Material describes that training is expected to cover how Protection Systems operate within their limitations and prevent possible damage to Elements. It also

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	3.2. Certificates • Reliability Operator • Balancing, Interchange and Transmission Operator • Balancing and Interchange Operator **PER-005-2 (Approved)** **R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: **1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-	addresses how RAS detect pre-determined BES conditions and automatically take corrective actions. The criteria that comprises operational functionality mirror the components listed under the NERC Glossary term "Protection System." By doing so, reduces the ambiguity of the phrase "purpose and limitations." The phrase "…applied in its area" is addressed by the PER-006-1 by using "…that affect the output of the generating Facility it operates." Lastly, the proposed PER-006-1 Requirement R1 includes both Protection Systems and RAS to eliminate confusion over the phrase "Protection System schemes." **Familiarity with the Purpose (BA)** For the BA, the PRC-001-1.1(ii), Requirement R1 is proposed for retirement on the basis that the BA obtains an appropriate level of familiarity with the purpose of Protection

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	related tasks identified in part 1.1 each calendar year. **1.2.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1. **1.3.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program. **1.4.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall	Systems and RAS under PER-003-1 (*Operating Personnel Credentials*), Requirement R3 and PER-005-2, Requirements R1, R3, R4, and R5 as explained below in detail. The BA is certified under PRC-003-1 as a System Operator.[14] Although there is no specific area of competency for protection and control similar to the Reliability Coordinator and Transmission Operator certifications, the NERC *Balancing and Interchange Operator Certification Exam Content Outline 2015*[15] (BI Exam) does contain the same five topics applicable to RC and less one topic applicable to the TOP. The topic that is not included is to "analyze relay targets, fault locaters and fault recorders to determine a proper restoration plan" and is not germane to BA operations. The job-task

[14] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a System Operator is defined as: An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System (BES) in Real-time.
[15] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Balancing%20and%20Interchange%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	implement the changes identified. **R2.** (Omitted – Transmission Owner, not applicable) **R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1. or Requirement R2 part 2.1. **3.1.** Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in	analyses (JTA) performed by entities are used to (1) develop the BI Exam topics that are evaluated by NERC and a NERC functional entity working group every three years, and (2) used to develop the training of personnel on company-specific reliability-related tasks under PER-005-2. Protection and control topics are addressed in the BI Exam outline under two areas: System Operations and Emergency Preparedness and Operations, and include the following five topics: • Analyze the impact of protection equipment outages on system reliability. • Ensure special protective systems and remedial action schemes are enabled when needed for system reliability. • Maintain adequate protective relaying during all phases of the system restoration.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Requirement R1 part 1.1. or Requirement R2 part 2.1. **R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. **4.1.** A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously	• Take action in response to alarms from special protective schemes. • Schedule system telecommunications, telemetering, protection, and control equipment outages to ensure system reliability. There is another certification that includes an integrated certification of both the BA and TOP called the *Balancing, Interchange, and Transmission Operator Certification Exam Content Outline 2015*[16] (BIT Exam). This BIT Exam outline does include protection and control as an area of competency and contains the same topics found in the *Transmission Operator Certification Exam Content Outline 2015*. Under PER-005-2, the System Operator and Operation Support Personnel of the BA are identified in the requirements. To address the reliability objective of "shall be familiar

[16] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Balancing%20Interchange%20Transmission%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria. **R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. **5.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training. **R6.** Each Generator Operator shall use a systematic approach to develop and	with the purpose and limitations of Protection System schemes applied in its area," the BA uses its JTA to develop a list of its reliability-related tasks. Using its documented methodology, the BA must develop and implement training materials according to its training program (R1) using a systematic approach to training. The BA is required to verify the capabilities of its System Operators under Requirement R3. Under Requirement R4, the BA "that (1) has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1[17] with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that

[17] Requirement R2 is omitted here because it is applicable to the Transmission Owner and is not within the scope of this project.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	implement training to its personnel identified in Applicability Section 4.1.5.1. of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. **6.1.** Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training. **Operational Planning Analysis (OPA) (Revised)** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to: load forecasts; generation output levels; Interchange; known Protection System and **Remedial Action Scheme** status or	replicates the operational behavior of the BES." Requirement R5 addresses the Operations Support Personnel of the BA, which requires the BA to use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 that are applicable to System Operators. **Familiarity with the Purpose (TOP)** The TOP will ensure that the BES is operated within SOLs and IROLs by integrating the "functions and limitations" of Protection Systems and RAS into its OPA and RTA as proposed by the revisions to the definitions of OPA and RTA. For the TOP, the PRC-001-1.1(ii), Requirement R1 is proposed for retirement

Standard: PRC-001-1.1(ii) – System Protection Coordination		
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	degradation, **functions, and limitations**; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)[10] **Real-time Assessment (RTA) (Revised)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load; generation output levels; known Protection System and **Remedial Action Scheme** status or degradation, **functions, and limitations**; Transmission outages; generator outages;	on the basis that the TOP obtains a sufficient level of knowledge (i.e. be familiar with the purpose of Protection System schemes applied in its area) under PER-003-1 (*Operating Personnel Credentials*), Requirement R1 and PER-005-2, Requirements R1, R3, R4, and R5, as explained below in detail. The TOP is certified as a System Operator, and has an "area of competency" for "protection and control" as shown in the NERC *Transmission Operator Certification Exam Content Outline 2015*.[18] This represents a minimum competency in the area of protection and control. However, certified System Operators will receive company-specific training on Protection Systems and RAS through PER-005-2, Requirements. The job-task analyses (JTA) performed by entities are used to (1)

[10] Bolded text identifies the proposed revisions.
[18] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Transmission%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Interchange; Facility Ratings; and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)[11] **IRO-008-2 (Approved)** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its	develop the TO Exam topics that are evaluated by NERC and a NERC functional entity working group every three years, and (2) used to develop the training of personnel on company-specific reliability-related tasks under PER-005-2. Under PER-005-2, System Operator and Operation Support Personnel of the TOP are identified in the requirements. To address the reliability objective of "shall be familiar with the purpose and limitations of Protection System schemes applied in its area," the TOP uses its JTA to develop a list of its reliability-related tasks. Using its documented methodology, the TOP must develop and implement training materials according to its training program (R1) using a systematic approach to training. The TOP is required to verify the capabilities of its System Operators under Requirement R3. Under Requirement R4, the TOP "that (1)

[11] Bolded text identifies the proposed revisions.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1[19] with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES." Requirement R5 addresses the Operations Support Personnel of the TOP, which requires the TOP to use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1. Operations Support Personnel are among the personnel that perform Operational

[19] Requirement R2 is omitted here because it is applicable to the Transmission Owner and is not within the scope of this project.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	IRO-010-2 (Approved) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.1.** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data.	Planning Analyses (OPA) and Real-time Assessments (RTA). These reliability-related-tasks, include performing both an OPA and RTA and are proposed for modification to address the integration of Protection System and RAS functions and limitations to ensure the BES is operated within SOLs and IROLs. See the discussion below concerning the OPA and RTA for the explanation of how the revised definitions support the reliability objective of PRC-001-1.1(ii), Requirement R1. **Reliability Coordinator (RC)** The standard PRC-001-1.1(ii) did not include the RC as an applicable functional entity; however, the RC is included here to further support the explanation on how the RC, along with the TOP, ensures the BES is operated within SOLs and IROLs by integrating the functions and limitations of

Standard: PRC-001-1.1(ii) – System Protection Coordination		
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	1.4. The deadline by which the respondent is to provide the indicated data. **TOP-001-3 (Approved)** **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **TOP-002-4 (Approved)** **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its	Protection Systems and RAS into its OPA and RTA. The RC obtains a sufficient level of knowledge (i.e. be familiar with the purpose and limitations of Protection System schemes applied in its area) under PER-003-1 (*Operating Personnel Credentials*), Requirement R1 and PER-005-2, Requirements R1, R3, R4, and R5. The RC is certified as a System Operator, and has an "area of competency" for "protection and control" as shown in the NERC *Reliability Coordinator Certification Exam Content Outline 2015*.[20] This represents a minimum competency in the area of protection and control. However, certified System Operators will receive company-specific training on Protection Systems and RAS through PER-005-2, Requirements.

[20] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Reliability%20Coordinator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **R3.** Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).	Under PER-005-2, System Operator and Operation Support Personnel of the RC are identified in the requirements. To similarly address the reliability objective of "shall be familiar with the purpose and limitations of Protection System schemes applied in its area" in PRC-001-1.1(ii), Requirement R1, the RC uses its JTA to develop a list of its reliability-related tasks. Using its documented methodology, the RC must develop and implement training materials according to its training program (R1) using a systematic approach to training. The RC is required to verify the capabilities of its System Operators under Requirement R3. Under Requirement R4, the RC that (1) has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1[21] with emergency

[21] Requirement R2 is omitted because it is applicable to the Transmission Owner and is not within the scope of this project.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES." Requirement R5 addresses the Operations Support Personnel of the RC, which requires the RC to use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1. Operations Support Personnel are among the personnel that perform Operational Planning Analyses (OPA) and Real-time Assessments (RTA). These reliability-related tasks include performing both an OPA and RTA and are proposed for modification to address the integration of Protection System and RAS functions and limitations to ensure the BES is operated within SOLs and IROLs. See the discussion below concerning the OPA and

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		RTA for the explanation of how the revised definitions support the reliability objective of PRC-001-1.1(ii), Requirement R1. **Operational Planning Analysis (OPA)** The TOP, applicable to PRC-001-1.1(ii), Requirement R1, is required have an OPA that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its SOLs (TOP-002-4, Requirement R1). The TOP is required to have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified as a result of its OPA as required in Requirement R1 (TOP-002-4, Requirement R2) and notify others of their role in the Operating Plan(s) (TOP-002-4, Requirement R4). To accomplish this, the TOP is required to maintain a documented data specification for the data necessary to perform its OPA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts

Standard: PRC-001-1.1(ii) – System Protection Coordination		
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		System reliability (TOP-003-3, Requirement R1, Part 1.2.). The RC is not applicable to PRC-001-1.1(ii) and is included here for additional support. The RC is required to perform an OPA that will allow it to assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area (IRO-008-2, Requirement R1). The RC is required to have a coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances identified as a result of its OPA as performed in Requirement R1 (IRO-008-2) while considering the Operating Plans for the next-day provided by its TOPs and BAs (IRO-008-2, Requirement R2). To accomplish this the RC is required to maintain a documented data specification for the data necessary to perform its OPA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		System reliability (IRO-010-2, Requirement R1, Part 1.2.). **Real-time Assessment (RTA)** The TOP, applicable to PRC-001-1.1(ii), Requirement R1, is required to ensure that an RTA is performed at least once every 30 minutes (TOP-001-3, Requirement R13). The TOP is required to initiate its Operating Plan to mitigate a SOL exceedance identified as part of its RTA (TOP-001-3, Requirement R14). To accomplish this the TOP is required to maintain a documented data specification for the data necessary to perform its RTA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts System reliability (TOP-003-3, Requirement R1, Part 1.2.). The RC is not applicable to PRC-001-1.1(ii) and is included here for additional support. The RC is required to ensure that a RTA is performed at least once every 30 minutes (IRO-008-4, Requirement R4). The RC is

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		required to notify impacted Transmission Operators and Balancing Authorities within its RC Area, and other impacted RCs as indicated in its Operating Plan, when the results of a RTA indicate an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area (IRO-008-2, Requirement R5). To accomplish this the RC is required to maintain a documented data specification for the data necessary to perform its RTA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts System reliability (IRO-010-2, Requirement R1, Part 1.2.).
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	PRC-001-1.1(ii), Requirements R2, R2.1., and R2.2. are proposed for retirement. The subsequent sections are organized in the following manner: • Corrective Action,	**Introduction** **Requirement PRC-001-1.1(ii), Requirement R2** The reliability objective of Requirement R2 and its sub-requirements ensure that the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	• Time Frame for corrective actions • Time Frame for notifications, • Shall notify, and • Protection System Inputs for notification	GOP and TOP take corrective action, as soon as possible, if a protective relay or equipment failure reduces system reliability. The subsequent explanation provides detail on how the TOP/IRO set of Reliability Standards (e.g., IRO-001-4, IRO-008-2, IRO-010-2, TOP-001-3, and TOP-003-3) that were developed since the Order was issued achieve the reliability objectives of PRC-001-1.1(ii), Requirement R2 and its sub-requirements. **Directives** Included in the explanation below is how these Reliability Standards address the directives in the Order at P 1441, 1444, 1445 and 1449 (#2 and #3). **Other** The phase "relay or equipment" in PRC-001-1.1(ii), Requirement R2 is clarified by the use of the defined NERC Glossary term, "Protection System" and "RAS."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing	PRC-001-1.1(ii), Requirements R2, R2.1., and R2.2. are proposed for retirement. Corrective action in Requirements R2, R2.1. and R2.2. is covered by: **TOP-001-3 (Approved)** **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission	**Introduction – Corrective Action** The directive at P 1449 (#3) of the Order states that: "…transmission operators must carry out corrective control actions, i.e., return a system to a stable state that respects system requirements…" This directive is addressed in the TOP/IRO standards that were developed since the Order was issued because the BA, RC, and TOP can issue Operating Instructions[22] to maintain the reliability of its respective area. The following describes how the TOP/IRO Reliability Standards achieve the reliability objective with regard to "corrective actions." **Corrective Action by the GOP – R2.1.** TOP-003-3 (*Operations Reliability Data*)

[22] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Operating Instruction is defined as "[a] command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)"

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement / Term in Standard	**Translation to Standard or Other Action**	**Comments**
Authorities. The Transmission Operator shall take corrective action as soon as possible. **PRC-001-1.1(ii) (Existing)**	Operator Area via its own actions or by issuing Operating Instructions. **R2.** Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. **TOP-003-3 (Approved)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	Requirement R1 and part 1.2. that was developed since the Order was issued addresses corrective action by the GOP because the TOP will be aware of current Protection System and SPS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the TOP receives such notification. TOP-001-3 (*Transmission Operations*) Furthermore, the TOP will act to maintain the reliability of its Transmission Operator Area[23] (TOP Area) by issuing Operating Instructions to the GOP under TOP-001-3, Requirement R1. TOP-003-3 (*Operations Reliability Data*)

[23] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Transmission Operator Area is defined as "[t]he collection of Transmission assets over which the Transmission Operator is responsible for operating."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement / Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	Similarly, TOP-003-3, Requirement R2 and part 2.2. that was developed since the Order was issued, addresses corrective action by the GOP because the BA (i.e., Host BA[24]) will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the BA receives such notification. The BA will act to maintain the reliability of its Balancing Authority Area[25] (BA Area) by issuing Operating Instructions to the GOP under TOP-001-3, Requirement R2. **Corrective Action by the TOP – R2.2.** TOP-003-3 (*Operations Reliability Data*)

[24] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Host Balancing Authority is defined as:

1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries.
2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.

[25] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Balancing Authority Area is defined as "[t]he collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.		Requirement R1 and part 1.2. that was developed since the Order was issued addresses corrective action by the TOP because the TOP will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the TOP receives such notification. TOP-001-3 (*Transmission Operations*) The TOP will act to maintain the reliability of its TOP Area by issuing Operating Instructions under TOP-001-3, Requirement R2. TOP-003-3 (*Operations Reliability Data*) Similarly, TOP-003-3, Requirement R2 and part 2.2. that was developed since the Order was issued addresses corrective action by the BA because the BA will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**IRO-010-2 (Approved)** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **IRO-001-4 (Approved)** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.”	reliability. See the “shall notify” section(s) below for a full description of how the TOP receives such notification. The BA will act to maintain the reliability of its BA Area by issuing Operating Instructions under TOP-001-3, Requirement R2. IRO-010-2 (*Reliability Coordinator Data Specification and Collection*) Requirement R1 and part 1.2. that was developed since the Order was issued addresses corrective action by the RC because the RC will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the “shall notify” section(s) below for a full description of how the RC receives such notification. IRO-001-4 (*Reliability Coordination - Responsibilities and Authorities*) Under Requirement R1, the RC will act to address the reliability of its Reliability

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		Coordinator Area[26] (RC Area) by issuing Operating Instructions.
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing	PRC-001-1.1(ii), Requirements R2, R2.1, and R2.2. are proposed for retirement. The time frame for corrective action in Requirements R2, R2.1. and R2.2. is covered by:	**Introduction – Time frame for corrective actions** The directive at P 1441 directs the ERO to clarify the term "corrective action" consistent with the discussion in the Order when it modifies PRC-001-1 in the Reliability Standards development process. The reasoning for addressing a time frame for corrective actions is amplified in P 1443 of the Order, which states that: "As explained above *[in the previous paragraphs of the Order*], the requirement for system operators to take corrective control action when protective relay or equipment failure reduces system reliability should be treated the same as the requirement for returning a system to a secure and reliable state after an

[26] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Balancing Authority Area is defined as "[t]he collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Authorities. The Transmission Operator shall take corrective action as soon as possible. **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its		Interconnection Reliability Operating Limit (IROL) violation, i.e., as soon as possible, but no longer than 30 minutes after a violation. A longer time limit would place an entity in violation of relevant IROL or TOP Reliability Standards."[27] At P 1444 of the Order, FERC directed NERC to consider the comments of the California PUC regarding the term "as soon as possible" as applicable to the maximum time frame for corrective action through the Standards development process. At P 1445 of the Order, FERC directed NERC, through the Reliability Standards development process, to determine the appropriate amount of time after the detection of relay failures, in which relevant transmission operators must be informed of such failures.

[27] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Interconnection Reliability Operating Limit is defined as "[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**TOP-001-3 (Approved)** **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.	The Order at P 1449 (#3) directs NERC to clarify that, after being informed of failures in relays or protection system elements that threaten reliability of the Bulk-Power System, transmission operators must carry out corrective control actions, i.e., return a system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes after they receive notice of the failure. **PRC-001-1.1(ii), R2.1. & R2.2. (time frame for corrective actions)** For the reasons explained below, a less than one-hour time frame criteria for corrective action will achieve the reliability objective directed in the Order at P 1441, 1444, 1445, and 1449 (#2 and #3). TOP-001-3 (*Transmission Operations*)

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the	**R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.	Requirement R13 requires the TOP to ensure that a Real-time Assessment[28] ("RTA") is performed at least once every 30 minutes and initiate its Operating Plan[29] to mitigate a System Operating Limit[30] (SOL) exceedance identified as part of its Real-time[31] monitoring or RTA in TOP-001-3, Requirement R14. The RTA requires inputs to include current Protection System and RAS status (change in status is implied) or

[28] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Real-time Assessment is defined as "[a]n evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)"

[29] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Operating Plan is defined as "[a] document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan."

[30] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a System Operating Limit is defined as "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)"

[31] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), Real-time is defined as "[p]resent time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)"

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**IRO-008-2 (Approved)** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.	degradation (including failure) from a BA, GOP, and/or TOP. Under TOP-003-3 notification of these inputs must occur within a 30 minute time frame; otherwise, a valid RTA cannot be performed once every 30 minutes. Given the periodicity for obtaining the data and performing the RTA, the exposure (i.e., time frame) for taking corrective action "as soon as possible" is expected to be less than one hour. The TOP may issue Operating Instructions to maintain reliability upon the notification of Protection System or RAS status (change in status is implied) or degradation (including failure) because the exposure is not expected to exceed one hour. The TOP must act under TOP-001-3, Requirement R1 to maintain the reliability of its TOP Area via its own actions or by issuing Operating Instructions. IRO-008-2 (*Reliability Coordinator Operational Analyses and Real-time Assessments*), Requirement R4 requires the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	TOP-003-3 (Approved) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection	RC to ensure that an RTA is performed at least once every 30 minutes. The RTA requires inputs to include current Protection System and RAS status (change in status is implied) or degradation (including failure) from a BA, GOP, and/or TOP. TOP-003-3 (*Operations Reliability Data*) IRO-010-2 (*Reliability Coordinator Data Specification and Collection*) Under TOP-003-3 (TOP and BA) and IRO-010-2 (RC) notification of these inputs must occur within a 30 minute time frame; otherwise, a valid RTA cannot be performed once every 30 minutes. Given the periodicity for obtaining the data and performing the RTA, the exposure (i.e., time frame) for taking corrective action as soon as possible is expected to be less than one hour. The RC may issue Operating Instructions to maintain reliability upon the notification of Protection System or RAS status (change in status is implied) or degradation (including failure) because the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	System status or degradation that impacts System reliability. **IRO-010-2 (Approved)** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **IRO-001-4 (Approved)** **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.	exposure is not expected to exceed one hour. IRO-001-4 (*Reliability Coordination - Responsibilities and Authorities*) The RC must act under IRO-001-4, Requirement R1 to maintain the reliability of its RC Area via its own actions or by issuing Operating Instructions.

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Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	PRC-001-1.1(ii), Requirements R2, R2.1., and R2.2 are proposed for retirement. The time frame for notification in Requirements R2, R2.1. and R2.2. is covered by: **IRO-008-2 (Approved)** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **TOP-001-3 (Approved)**	**Introduction – Time frame for notifications and shall notify** The directive at P 1444 of the Order directed NERC to consider the comments of FirstEnergy about the time frame between actual failure and its discovery (i.e., notification) in relation to the maximum time frame for corrective action through the Standards development process. The Order at P 1445 and 1449 (#2) directed NERC to determine an appropriate amount of time after the detection of relay failures and the time in which relevant generation and transmission operators must be informed of such failure. **PRC-001-1.1(ii), R2.1. & R2.2. (time frame for notifications)** TOP-001-3 (*Transmission Operations*) For the reasons explained below concerning notification, it is inferred that the timeframe for notification must occur on at least a 30

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	**R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **TOP-003-3 (Approved)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis	minute interval because the RTA performed by the RC (IRO-008-2) and TOP (TOP-001-3) once every 30 minutes requires the data to be available on at least a 30 minute basis such that the exposure is less than one hour. TOP-003-3 (*Operations Reliability Data*) Notification in PRC-001-1.1(ii), Requirement R2.1. and R2.2. is addressed by TOP-003-3, Requirement R1, part 1.2. for TOP and Requirement R2, part 2.2. for BA that were developed since the Order was issued. Requirements R1 and R2 mandate that the TOP and BA have provisions (i.e., inputs) for notification of Protection System and RAS status (change in status is implied) or degradation (including failures) that impacts System reliability. **PRC-001-1.1(ii), R2.1. (shall notify)** Based on the conclusions above (i.e., “time frame for corrective actions”), notifications of the inputs of Protection Systems and RAS

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible. **PRC-001-1.1(ii) (Existing)**	functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. **R4.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	by the GOP must be provided on at least a 30-minute basis. The TOP/IRO set of standards that were developed since the Order was issued achieve the reliability objective of ensuring that the BA (i.e., Host BA) and TOP are notified of protective relay and equipment failures. TOP-003-3 (*Operations Reliability Data*) TOP-003-3, Requirement R1 mandates the TOP have a documented specification for the data necessary for the TOP to perform an Operational Planning Analysis ("OPA"),[32] Real-time monitoring, and RTA. Both the OPA and RTA, by definition, require an evaluation that reflects inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure). TOP-003-3, Requirement R3 mandates the TOP distribute its documented

[32] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Operational Planning Analysis is defined as "[a]n evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: **5.1.** A mutually agreeable format **5.2.** A mutually agreeable process for resolving data conflicts **5.3.** A mutually agreeable security protocol. **TOP-003-3 (Approved) (included again for reference)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The	specification to those entities that have the required data, which includes the GOP. TOP-003-3, Requirement R2 mandates the BA have a documented specification for the data necessary for the BA to perform its analysis functions and Real-time monitoring that include inputs from Protection System and RAS status (change in status is implied) or degradation that are necessary to maintain generation-Load-Interchange balance. TOP-003-3, Requirement R4 mandates the BA to distribute its documented specification to those entities that have the required data, which includes the GOP. TOP-003-3, Requirement R5 builds upon the previous Requirements R1, R2, R3, and R4 described above. Requirement R5 mandates that any GOP that receives a data specification (pursuant to Requirement R3 or R4) satisfy the obligations of the documented specifications using: a mutually agreeable format, a mutually agreeable

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.	process for resolving data conflicts, and a mutually agreeable security protocol. Therefore, the reliability objective of PRC-001-1.1(ii) Requirement R2, R2.1 that mandates the GOP notify its TOP and Host BA of protective relay and equipment failures is addressed by the documented specification for the data required in TOP-003-3, Requirement R1, part 1.2. for TOP and Requirement R2, part 2.2. for the BA. The documented data specifications is required to be distributed by the TOP and BA and mandates the GOP, per TOP-003-3 Requirement R5, provide current Protection System and RAS status (change in status is implied) or degradation that impacts System reliability. **PRC-001-1.1(ii), R2.2. (shall notify)** Based on the conclusions above (i.e., "time frame for corrective actions), notifications of the inputs of Protection Systems and RAS by the TOP must be provided on at least a 30-minute basis. The TOP/IRO set of standards

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	TOP-003-3 (Approved) (included again for reference) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection	that were developed since the Order was issued achieve the reliability objective of ensuring that the RC and the BA and TOP (i.e., the affected BA and TOP) are notified of protective relay and equipment failures. TOP-003-3 (*Operations Reliability Data*) TOP-003-3, Requirement R1, mandates the TOP have a documented specification for the data necessary for the TOP to perform an OPA, Real-time monitoring, and RTA. Both the OPA and RTA, by definition, require an evaluation to reflect inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure). TOP-003-3, Requirement R3 mandates the TOP distribute its documented specification to those entities that have the required data, which includes the BA, RC, and TOP. TOP-003-3, Requirement R2 mandates the BA have a documented specification for the data necessary for the BA to perform its analysis functions and Real-time monitoring,

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement / Term in Standard	**Translation to Standard or Other Action**	**Comments**
	System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.	which would include inputs from Protection System and RAS status (change in status is implied) or degradation that are necessary to maintain generation-Load-Interchange balance. TOP-003-3, Requirement R4 mandates the BA distribute its documented specification to those entities that have the required data, which includes the BA, RC, and TOP. TOP-003-3, Requirement R5 builds upon the previous Requirements R1, R2, R3, and R4 described above. Requirement R5 mandates that any TOP that receives a data specification (pursuant to Requirement R3 or R4) satisfy the obligations of the documented specifications using: a mutually agreeable format, a mutually agreeable process for resolving data conflicts, and a mutually agreeable security protocol. **Common to both the GOP and TOP** IRO-010-2 (*Reliability Coordinator Data Specification and Collection*)

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	IRO-010-2 (Approved) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	Requirement R1, mandates the RC have a documented specification for the data necessary for the RC to perform an OPA, Real-time monitoring, and RTA. Both the OPA and RTA, by definition, require an evaluation to reflect inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure). IRO-010-2, Requirement R2 mandates the RC distribute its documented specification to those entities that have the required data, which includes the BA, RC, and TOP. IRO-010-2, Requirement R3 builds upon the previous Requirements R1 and R2 described above. Requirement R3 mandates that a TOP that receives a data specification (pursuant to Requirement R2) satisfy the obligations of the documented specifications using: a mutually agreeable format, a mutually agreeable process for resolving data conflicts, and a mutually agreeable security protocol.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		Therefore, the reliability objective of PRC-001-1.1(ii) Requirement R2, R2.2. mandates the TOP to notify its RC and affected BA and TOP of protective relay and equipment failures is addressed by the documented specification for the data required in TOP-003-3, Requirement R1, part 1.2. for the TOP and Requirement R2, part 2.2. for the BA, and IRO-010-2, Requirement R1 for the RC. The documented data specifications is required to be distributed by the TOP and will require the RC per IRO-010-2, Requirement R3 and the BA and TOP per TOP-003-3, Requirement R5 to provide current Protection System and RAS status (change in status is implied) or degradation that impacts System reliability.
PRC-001-1.1(ii) (Existing) **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.	**PRC-027-1 (NERC Board approved)** The mapping of PRC-001-1.1(ii), Requirements R3, R3.1 and R3.2 are addressed in a different project. See Project 2007-06 System Protection Coordination	N/A

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. • Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition. **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	(i.e., Phase 1) concerning proposed Reliability Standard PRC-027-1.	
PRC-001-1.1(ii) (Existing) **R4.** Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators,	**PRC-027-1 (NERC Board approved)** The mapping of PRC-001-1.1(ii), Requirement R4 is addressed in a different project. See Project 2007-06 System Protection Coordination (i.e., Phase 1)	N/A

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Transmission Operators, and Balancing Authorities.	concerning proposed Reliability Standard PRC-027-1.	
PRC-001-1.1(ii) (Existing) **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems. **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	PRC-001-1.1(ii), Requirements R5, R5.1, and R5.2 are proposed for retirement. The notification in advance in Requirements R5, R5.1 and R5.2 is covered by:	**Introduction – Shall notify in advance** For the reasons explained under the "shall notify" sections above, the TOP will receive notifications of known current Protection Systems and RAS status (change in status is implied) or degradation (including failure) from the GOP and TOP under TOP-003-3 that was developed since the Order was issued. Advance notification to the TOP will occur through IRO-008-2, IRO-017-1 (*Outage Coordination*), and TOP-002-4 (*Operations Planning*) that were developed since the Order was issued, and through the existing TPL-001-4 (*Transmission System Planning Performance Requirements*). **PRC-001-1.1(ii), R5.1 and R5.2 (shall notify in advance)**

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating	**TPL-001-4 (Existing)** **R4.** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case	The following explains how the reliability objective of the GOP and TOP coordinating changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of other TOPs is met. TPL-001-4 (*Transmission System Planning Performance Requirements*) Requirement R4 (Requirement R2 is inferred by reference) focuses on the Planning Assessment[33] performed by either the PC or the TP with aspects of Protection Systems and RAS. Additionally, the projected Contingency conditions that are evaluated under TPL-001-4 by the PC and TP are considered by the TOP in performing an OPA.

[33] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Planning Assessment is defined as a "[d]ocumented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
conditions that could require changes in the Protection Systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems. **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	analyzed in accordance with Requirements R2, Parts 2.1.4. and 2.4.3. The Corrective Action Plan(s) shall: **IRO-002-4 (Approved)** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **TOP-002-4 (Approved)** **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning	IRO-002-4 (*Reliability Coordination — Monitoring and Analysis*) Requirement R3 supports the inclusion of the Reliability Coordinator. This function also has a responsibility to have knowledge (i.e. be familiar with the purpose and limitations) of Protection Systems and RAS since it is monitoring Facilities, the status of RAS, and non-BES facilities. TOP-002-4 (*Operations Planning*) The approved TOP-002-4, Requirement R1 that was developed since the Order was issued requires the TOP to have an OPA that will allow the TOP to assess whether its planned operations for the next day (i.e., "in advance") within its TOP Area will exceed any of its SOLs. The OPA requires inputs to

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.	Analyses, Real-time monitoring, and Real-time Assessments. **TOP-003-3 (Approved)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	assess anticipated (pre-Contingency[34]) and potential (post-Contingency) conditions for next-day operations. The TOP when performing its next-day planning through an OPA, will receive the necessary data "in advance" under TOP-003-3 and evaluate the projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for when generation, transmission, load, or operating conditions that could require changes in the other Transmission Operator's Protection Systems. By definition, an OPA evaluation shall reflect applicable inputs including Protection System and RAS status (change in status is implied) or degradation, but is not limited to: • load forecasts,

[34] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Contingency is defined as "[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	**IRO-008-2 (Approved)** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System	• generation output levels, • Interchange, • known Protection System and RAS status or degradation, • Transmission outages, • generator outages, • Facility Ratings, and • identified phase angle and equipment limitations. IRO-008-2 (*Reliability Coordinator Operational Analyses and Real-time Assessments*) IRO-008-2, Requirement R2 requires each RC to have coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances. These exceedances are identified as a result of an OPA being performed in IRO-008-2, Requirement R1 while considering the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **IRO-017-1 (Approved)** **R3.** Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. **R4.** Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or	Operating Plans for the next-day provided by each BA and TOP. Collectively, performing the OPA under TOP-002-4 using the necessary inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure), the Planning Assessment conducted under TPL-001-4, the jointly developed solutions under IRO-017-2, communication from the RC to the TOP under IRO-005-4, and the coordinated Operating Plan(s) under IRO-008-2 achieve the reliability objective of both PRC-001-1.1(ii), Requirements R5.1 and R5.2 for “when changes in generation, transmission, load, or operating conditions could require changes in the other Transmission Operator’s Protection Systems.” IRO-017-1 (*Outage Coordination*) IRO-017-1, Requirement R3 requires each PC and TP to provide its Planning Assessment to an impacted RC. IRO-017-1, Requirement R4 requires each PC and TP to jointly develop

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.	solutions with each respective RC for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.[35]
PRC-001-1.1(ii) (Existing) **R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Requirement R6 is being proposed for retirement. The monitoring and notification in Requirement R6 is covered by: **IRO-002-4 (Approved)** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability	**PRC-001-1.1(ii), R6 (monitoring and notification of RAS)** IRO-002-4 (*Reliability Coordination — Monitoring and Analysis*) The reliability objective for the monitoring of RAS is addressed by IRO-002-4, Requirement R3 for the Reliability Coordinator.

[35] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Near-Term Transmission Planning Horizon is defined as “[t]he transmission planning period that covers Year One through five.”

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Operating Limit exceedances within its Reliability Coordinator Area. **TOP-001-3 (Approved)** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **10.1.** Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and **10.2.** Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency	TOP-001-3 (*Transmission Operations*) The reliability objective for the monitoring of RAS is addressed by TOP-001-3, Requirements R10 and R11 for the TOP and BA, respectively, because they are required to monitor the status of a RAS. Notification of the change in status is addressed for the reasons explained under the "shall notify" sections above. In summary, the BA and TOP will receive notifications of inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure) from the applicable GOP and/or TOP under TOP-003-3 that was developed since the Order was issued.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	TOP-003-3 (approved) included by reference. See the section called, “shall notify.”	

Mapping Document

Project 2007-06.2 Phase 2 of System Protection Coordination

Revisions or Retirements to Already Approved Standards

This mapping document explains how each of the existing Requirements (R1, R2, R5, and R6) of PRC-001-1.1(ii) (*System Protection Coordination*)[1] are being revised or retired. If a requirement is being proposed for revision, the revised, new, and/or supporting requirement(s) will be identified in the center column. If a requirement is being proposed for retirement, the center column will describe the proposed action and any requirement(s) used to support the action. Revisions and retirements will be accompanied by an explanation or justification listed in the right column. Capitalized terms, unless otherwise noted, are those found in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary").[2] References to regulatory directives are specifically related to Order No. 693 ("Order").[3] Standards or definitions listed as "existing" are enforceable and those listed as "approved" have been adopted by the NERC Board of Trustees and approved by the Federal Energy Regulatory Commission ("FERC"). Check the NERC website for effective dates. The functional entities discussed in the mapping document are the Balancing Authority (BA), Generator Operator (GOP), Planning Coordinator (PC), Reliability Coordinator (RC), Transmission Operator (TOP), and Transmission Planner (TP). The term "TOP/IRO" refers to the Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) sets of Reliability Standards that were filed under NERC Project 2014-03 – Revisions to TOP and IRO Standards[4] and approved by FERC.[5] The explanation herein assumes that the term, "Special Protection

[1] Federal Energy Regulatory Commission (FERC) approved PRC-001-1.1(ii), effective May 29, 2015.
[2] *Glossary of Terms Used in NERC Reliability Standards*. December 7, 2015. (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).
[3] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 ("Order No. 693"), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
[4] http://www.nerc.com/pa/Stand/Pages/Project-2014-03-Revisions-to-TOP-and-IRO-Standards.aspx
[5] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order 817, 153 FERC ¶ 61,178 (November 19, 2015).

System"[6] (SPS) will be replaced by the term "Remedial Action Scheme"[7] (RAS). In the referenced Reliability Standards herein the term SPS may be replaced by RAS; therefore, the term RAS will be used in the "Comments" column throughout.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing)[8,9] **R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall be	PRC-001-1.1(ii), Requirement R1 is proposed for retirement.	**Introduction** The reliability objective of PRC-001-1.1(ii), Requirement R1 is to ensure that the BA,

[6] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Special Protection System is defined as "[a]n automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme."

[7] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), the proposed definition of Remedial Action Scheme is defined as "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as: Meet requirements identified in the NERC Reliability Standards; Maintain Bulk Electric System (BES) stability; Maintain acceptable BES voltages; Maintain acceptable BES power flows; Limit the impact of Cascading or extreme events." See definition for additional information on the definition of RAS.

[8] Order No. 693 at P 1418. "Protection and Control systems (PRC) on Bulk-Power System elements are an integral part of reliable grid operation. Protection systems are designed to detect and isolate faulty elements on a system, thereby limiting the severity and spread of system disturbances, and preventing possible damage to protected elements. The function, settings and limitations of a protection system are critical in establishing SOLs and IROLs. The PRC Reliability Standards apply to transmission operators, transmission owners, generator operators, generator owners, distribution providers and regional reliability organizations and cover a wide range of topics related to the protection and control of power systems."

[9] Order No. 693 at P 1435. "Protection systems on Bulk-Power System elements are an integral part of reliable operations. They are designed to detect and isolate faulty elements on a power system, thereby limiting the severity and spread of disturbances and preventing possible damage to protected elements. If a protection system can no longer perform as designed because of a failure of its relays, system reliability is reduced or threatened. In deriving SOLs and IROLs, moreover, the functions, settings, and limitations of protection systems are recognized and integrated. Systems are only reliable when protection systems perform as designed. This is what PRC-001-1 means in linking a reduction in system reliability with a protection relay failure or other equipment failure."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
familiar with the purpose and limitations of Protection System schemes applied in its area. **Operational Planning Analysis (Approved)** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages;	Being "familiar with the purpose and limitations of Protection System schemes" will be clarified as (1) being "familiar with their purpose," and (2) being "familiar with their limitations" as follows: • The phrase "Protection systems schemes" maps to the NERC Glossary terms of Protection Systems and Remedial Action Schemes. • Being "familiar with the purpose" is addresses by existing and proposed training standards. • Being "familiar with the limitations" together with the clarification found in Order No. 693 at P 1418 and P 1435 along with the revised	GOP, and TOP are "familiar with the purpose and limitations of Protection System[12] schemes applied in its area." The reliability objective of the phrase "Protection System schemes" in PRC-001-1.1(ii), Requirement R1 is also intended to include RAS. The ~~function, settings~~functions and limitations of a Protection Systems and RAS are critical in establishing System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL) such that the Bulk Electric System[13] (BES) is operated within these limits. The following explains how being familiar with the purpose and

[12] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Protection System is defined as:
"Protection System -

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."

[13] See Glossary of Terms Used in NERC Reliability Standards (updated December 7, 2015).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Real-time Assessment (Approved)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)	definitions of NERC Glossary defined terms of Operational Planning Analysis and Real-time Assessment address the reliability objective of PRC-001-1.1(ii), Requirement R1 as explained in the Comments column to the right. **PER-006-1 (New)** **4.** Applicability: **4.1.** Functional Entities: **4.1.1.** Generator Operator that have: **4.1.1.1.** Plant personnel who are responsible for the Real-time control of a generator and receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center. This does not include personnel at a centrally located dispatch center.	limitations of Protection Systems and RAS will be addressed according to issue beginning with "familiarity with their limitations" and then "familiarity with their purpose." **Familiar with their limitations** When the BA, GOP, and TOP are familiar with the ~~settings and limits (i.e.,~~ limitations~~)~~ of Protection Systems and RAS, the entities are able to operate the BES in such a manner that Protection Systems and RAS will be operated within their limits and be able to detect and isolate faulty Elements, thereby, limiting the severity and spread of system disturbances, and preventing possible damage to protected Elements. When the GOP is familiar with the ~~limitations~~operational functionality of Protection Systems and RAS by being trained on how Protection Systems operate and prevent possible damage to Elements, the GOP is capable of operating to its full

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	R1. Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of ~~a~~the generating Facility(ies) it operates. **PER-003-1 (Existing)** **R1.** Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate: **1.1.** Areas of Competency **1.1.1.** Resource and demand balancing **1.1.2.** Transmission operations **1.1.3.** Emergency preparedness and operations	capability within its area, meaning the output of its generation Facilities. When the BA is familiar with the limitations of Protection Systems and RAS, it is capable of maintaining generation, Load, and Interchange balance. The BA ensures that RAS in its area are enabled when needed for system reliability. When the TOP is familiar with limitations of Protection Systems and RAS, it will be capable of identifying when system reliability is reduced or threatened. In operating to established SOLs and IROLs, it is important that the functions~~, settings,~~ and limitations of Protection Systems and RAS are recognized and integrated by the TOP into operating the BES reliably. The BES is only reliable when Protection Systems and RAS perform within their limitations. **Familiarity with the Purpose** Familiarity with the purpose of Protection Systems and RAS is achieved through training, as explained below, according to

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	1.1.4. System operations **1.1.5.** Protection and control **1.1.6.** Voltage and reactive **1.1.7.** Interchange scheduling and coordination **1.1.8.** Interconnection reliability operations and coordination **R2.** Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates: **2.1.** Areas of Competency **2.1.1.** Transmission operations **2.1.2.** Emergency preparedness and operations **2.1.3.** System operations **2.1.4.** Protection and control	each applicable entity (BA, GOP, and TOP) in PRC-001-1.1(ii) and the RC that is not applicable to this standard, but has been included to address a potential gap in reliability. **Familiarity with the Purpose (GOP)** For the GOP, the Reliability Standard PER-006-1 (*Specific Training for Personnel*) proposes to replace PRC-001-1.1(ii), Requirement R1. The PER-006-1 standard identifies applicable GOP personnel that are responsible for the Real-time control of a generator and that receive Operating Instructions from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center. This applicability removes ambiguity over which personnel of the GOP are intended to be familiar with the purpose Protection Systems and RAS. Centrally located personnel are not included here because they are addressed by PER-005-2 (*Operations Personnel Training*). Personnel

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	2.1.5. Voltage and reactive **2.2.** Certificates • Reliability Operator • Balancing, Interchange and Transmission Operator • Transmission Operator **R3.** Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificate: **3.1.** Areas of Competency **3.1.1.** Resources and demand balancing **3.1.2.** Emergency preparedness and operations **3.1.3.** System operations **3.1.4.** Interchange scheduling and coordination	at centrally located dispatch centers will receive company-specific Protection System and RAS training, if identified, as a reliability-related task via the PER-005-2, Requirement R6. Here the GOP must use "…a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1. of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations." Being trained using a systematic approach on the purpose (i.e., functions, including ~~limits~~limitations) Protection Systems and RAS will enable the GOP centrally located dispatch personnel to ensure reliable operation of its Facilities on the BES. The phrase "…purpose and limitations…" in PRC-001-1-1(ii), Requirement R1 is addressed in the proposed ~~requirement~~Requirement R1 through the use of "operational functionality." The phrase "operational functionality" as described in the PER-006-1 – ~~Application~~

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	3.2. Certificates • Reliability Operator • Balancing, Interchange and Transmission Operator • Balancing and Interchange Operator **PER-005-2 (Approved)** **R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: **1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-	~~Guidelines~~Supplemental Material describes that training is expected to cover how Protection Systems operate within their ~~limits~~limitations and prevent possible damage to Elements. It also addresses how RAS detect pre-determined BES conditions and automatically take corrective actions. The criteria that comprises operational functionality mirror the components listed under the NERC Glossary term "Protection System." By doing so, reduces the ambiguity of the phrase "purpose and limitations." The phrase "…applied in its area" is addressed by the PER-006-1 by using "…that affect the output of ~~a~~the generating Facility it operates." Lastly, the proposed PER-006-1 Requirement R1 includes both Protection Systems and RAS to eliminate confusion over the phrase "Protection System schemes." **Familiarity with the Purpose (BA)**

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	related tasks identified in part 1.1 each calendar year. **1.2.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1. **1.3.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program. **1.4.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall	For the BA, the PRC-001-1.1(ii), Requirement R1 is proposed for retirement on the basis that the BA obtains an appropriate level of familiarity with the purpose of Protection Systems and RAS under PER-003-1 (*Operating Personnel Credentials*), Requirement R3 and PER-005-2, Requirements R1, R3, R4, and R5 as explained below in detail. The BA is certified under PRC-003-1 as a System Operator.[14] Although there is no specific area of competency for protection and control similar to the Reliability Coordinator and Transmission Operator certifications, the NERC *Balancing and Interchange Operator Certification Exam Content Outline 2015*[15] (BI Exam) does contain the same five topics applicable to RC and less one topic applicable to the TOP. The

[14] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a System Operator is defined as: An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System (BES) in Real-time.
[15] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Balancing%20and%20Interchange%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	implement the changes identified. **R2.** (Omitted – Transmission Owner, not applicable) **R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1. or Requirement R2 part 2.1. **3.1.** Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in	topic that is not included is to "analyze relay targets, fault locaters and fault recorders to determine a proper restoration plan" and is not germane to BA operations. The job-task analyses (JTA) performed by entities are used to (1) develop the BI Exam topics that are evaluated by NERC and a NERC functional entity working group every three years, and (2) used to develop the training of personnel on company-specific reliability-related tasks under PER-005-2. Protection and control topics are addressed in the BI Exam outline under two areas: System Operations and Emergency Preparedness and Operations, and include the following five topics: • Analyze the impact of protection equipment outages on system reliability. • Ensure special protective systems and remedial action schemes are enabled when needed for system reliability.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Requirement R1 part 1.1. or Requirement R2 part 2.1. **R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. **4.1.** A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously	• Maintain adequate protective relaying during all phases of the system restoration. • Take action in response to alarms from special protective schemes. • Schedule system telecommunications, telemetering, protection, and control equipment outages to ensure system reliability. There is ~~a fourth~~another certification that includes an integrated certification of both the BA and TOP called the *Balancing, Interchange, and Transmission Operator Certification Exam Content Outline 2015*[16] (BIT Exam). This BIT Exam outline does include protection and control as an area of competency and contains the same topics found in the *Transmission Operator Certification Exam Content Outline 2015*.

[16] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Balancing%20Interchange%20Transmission%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria. **R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. **5.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training. **R6.** Each Generator Operator shall use a systematic approach to develop and	Under PER-005-2, the System Operator and Operation Support Personnel of the BA are identified in the requirements. To address the reliability objective of "shall be familiar with the purpose and limitations of Protection System schemes applied in its area," the BA uses its JTA to develop a list of its reliability-related tasks. Using its documented methodology, the BA must develop and implement training materials according to its training program (R1) using a systematic approach to training. The BA is required to verify the capabilities of its System Operators under Requirement R3. Under Requirement R4, the BA "that (1) has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1[17] with emergency operations training using simulation

[17] Requirement R2 is omitted here because it is applicable to the Transmission Owner and is not within the scope of this project.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	implement training to its personnel identified in Applicability Section 4.1.5.1. of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. **6.1.** Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training. **Operational Planning Analysis (OPA) (Revised)** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to~~,~~: load forecasts; generation output levels; Interchange; known Protection System and **Remedial Action Scheme** ~~(~~status or	technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES." Requirement R5 addresses the Operations Support Personnel of the BA, which requires the BA to use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 that are applicable to System Operators. **Familiarity with the Purpose (TOP)** The TOP will ensure that the BES is operated within SOLs and IROLs by integrating the "functions and ~~limits~~limitations" of Protection Systems and RAS into its OPA and RTA as proposed by the revisions to the definitions of OPA and RTA.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	degradation, **functions, and ~~limits~~limitations**; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)[10] **Real-time Assessment (RTA) (Revised)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load~~,~~; generation output levels~~,~~; known Protection System and **Remedial Action Scheme** ~~(~~status or degradation, ~~and~~ **functions, and** ~~limits),~~ limitations; Transmission outages~~,~~;	For the TOP, the PRC-001-1.1(ii), Requirement R1 is proposed for retirement on the basis that the TOP obtains a sufficient level of knowledge (i.e. be familiar with the purpose of Protection System schemes applied in its area) under PER-003-1 (*Operating Personnel Credentials*), Requirement R1 and PER-005-2, Requirements R1, R3, R4, and R5, as explained below in detail. The TOP is certified as a System Operator, and has an "area of competency" for "protection and control" as shown in the NERC *Transmission Operator Certification Exam Content Outline 2015*.[18] This represents a minimum competency in the area of protection and control. However, certified System Operators will receive company-specific training on Protection Systems and RAS through PER-005-2,

[10] Bolded text identifies the proposed revisions.
[18] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Transmission%20Operator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	generator outages~~,~~; Interchange~~,~~; Facility Ratings~~,~~; and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)[11] **IRO-008-2 (Approved)** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL)	Requirements. The job-task analyses (JTA) performed by entities are used to (1) develop the ~~BI~~TO Exam topics that are evaluated by NERC and a NERC functional entity working group every three years, and (2) used to develop the training of personnel on company-specific reliability-related tasks under PER-005-2. Under PER-005-2, System Operator and Operation Support Personnel of the TOP are identified in the requirements. To address the reliability objective of "shall be familiar with the purpose and limitations of Protection System schemes applied in its area," the TOP uses its JTA to develop a list of its reliability-related tasks. Using its documented methodology, the TOP must develop and implement training materials according to its training program (R1) using a systematic approach to training. The TOP is required to verify the capabilities of its

11 Bolded text identifies the proposed revisions.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	System Operators under Requirement R3. Under Requirement R4, the TOP "that (1) has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1[19] with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES." Requirement R5 addresses the Operations Support Personnel of the TOP, which requires the TOP to use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1. Operations Support Personnel are among

[19] Requirement R2 is omitted here because it is applicable to the Transmission Owner and is not within the scope of this project.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	IRO-010-2 (Approved) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.1.** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	the personnel that perform Operational Planning Analyses (OPA) and Real-time Assessments (RTA). These reliability-related-tasks, include performing both an OPA and RTA and are proposed for modification to address the integration of Protection System and RAS ~~limits~~functions and limitations to ensure the BES is operated within SOLs and IROLs. See the discussion below concerning the OPA and RTA for the explanation of how the revised definitions support the reliability ~~object~~ objective of PRC-001-1.1(ii), Requirement R1. **Reliability Coordinator (RC)** The standard PRC-001-1.1(ii) did not include the RC as an applicable functional entity; however, the RC is included here to further support the explanation on how the RC, along with the TOP, ensures the BES is operated within SOLs and IROLs by integrating the ~~limits~~functions and

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	1.3. A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **TOP-001-3 (Approved)** **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **TOP-002-4 (Approved)** **R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its	limitations of Protection Systems and RAS into its OPA and RTA. The RC obtains a sufficient level of knowledge (i.e. be familiar with the purpose and limitations of Protection System schemes applied in its area) under PER-003-1 (*Operating Personnel Credentials*), Requirement R1 and PER-005-2, Requirements R1, R3, R4, and R5. The RC is certified as a System Operator, and has an "area of competency" for "protection and control" as shown in the NERC *Reliability Coordinator Certification Exam Content Outline 2015*.[20] This represents a minimum competency in the area of protection and control. However, certified System Operators will receive company-specific training on Protection Systems and RAS through PER-005-2, Requirements.

[20] http://www.nerc.com/pa/Train/SysOpCert/System%20Operator%20Certification%20DL/Reliability%20Coordinator%20Certification%20Exam%20Content%20Outline%202015.pdf (December 9, 2014).

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. **R3.** Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s).	Under PER-005-2, System Operator and Operation Support Personnel of the RC are identified in the requirements. To similarly address the reliability objective of "shall be familiar with the purpose and limitations of Protection System schemes applied in its area" in PRC-001-1.1(ii), Requirement R1, the RC uses its JTA to develop a list of its reliability-related tasks. Using its documented methodology, the RC must develop and implement training materials according to its training program (R1) using a systematic approach to training. The RC is required to verify the capabilities of its System Operators under Requirement R3. Under Requirement R4, the RC that (1) has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1[21] with emergency

[21] Requirement R2 is omitted because it is applicable to the Transmission Owner and is not within the scope of this project.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES." Requirement R5 addresses the Operations Support Personnel of the RC, which requires the RC to use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1. Operations Support Personnel are among the personnel that perform Operational Planning Analyses (OPA) and Real-time Assessments (RTA). These reliability-related tasks include performing both an OPA and RTA and are proposed for modification to address the integration of Protection System and RAS ~~limits~~functions and limitations to ensure the BES is operated within SOLs and IROLs. See the discussion below concerning the OPA

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		and RTA for the explanation of how the revised definitions support the reliability ~~object~~ objective of PRC-001-1.1(ii), Requirement R1. **Operational Planning Analysis (OPA)** The TOP, applicable to PRC-001-1.1(ii), Requirement R1, is required have an OPA that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its SOLs (TOP-002-4, Requirement R1). The TOP is required to have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified as a result of its OPA as required in Requirement R1 (TOP-002-4, Requirement R2) and notify others of their role in the Operating Plan(s) (TOP-002-4, Requirement R4). To accomplish this, the TOP is required to maintain a documented data specification for the data necessary to perform its OPA that includes provisions for notification of current Protection System and RAS status or

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		degradation (including failure) that impacts System reliability (TOP-003-3, Requirement R1, Part 1.2.). The RC is not applicable to PRC-001-1.1(ii) and is included here for additional support. The RC is required to perform an OPA that will allow it to assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area (IRO-008-2, Requirement R1). The RC is required to have a coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances identified as a result of its OPA as performed in Requirement R1 (IRO-008-2) while considering the Operating Plans for the next-day provided by its TOPs and BAs (IRO-008-2, Requirement R2). To accomplish this the RC is required to maintain a documented data specification for the data necessary to perform its OPA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		System reliability (IRO-010-2, Requirement R1, Part 1.2.). **Real-time Assessment (RTA)** The TOP, applicable to PRC-001-1.1(ii), Requirement R1, is required to ensure that an RTA is performed at least once every 30 minutes (TOP-001-3, Requirement R13). The TOP is required to initiate its Operating Plan to mitigate a SOL exceedance identified as part of its RTA (TOP-001-3, Requirement R14). To accomplish this the TOP is required to maintain a documented data specification for the data necessary to perform its RTA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts System reliability (TOP-003-3, Requirement R1, Part 1.2.). The RC is not applicable to PRC-001-1.1(ii) and is included here for additional support. The RC is required to ensure that a RTA is performed at least once every 30 minutes (IRO-008-4, Requirement R4). The RC is

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		required to notify impacted Transmission Operators and Balancing Authorities within its RC Area, and other impacted RCs as indicated in its Operating Plan, when the results of a RTA indicate an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area (IRO-008-2, Requirement R5). To accomplish this the RC is required to maintain a documented data specification for the data necessary to perform its RTA that includes provisions for notification of current Protection System and RAS status or degradation (including failure) that impacts System reliability (IRO-010-2, Requirement R1, Part 1.2.).
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	PRC-001-1.1(ii), Requirements R2, R2.1., and R2.2. are proposed for retirement. The subsequent sections are organized in the following manner: • Corrective Action,	**Introduction** **Requirement PRC-001-1.1(ii), Requirement R2** The reliability objective of Requirement R2 and its sub-requirements ensure that the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	• Time Frame for corrective actions • Time Frame for notifications, • Shall notify, and • Protection System Inputs for notification	GOP and TOP take corrective action, as soon as possible, if a protective relay or equipment failure reduces system reliability. The subsequent explanation provides detail on how the TOP/IRO set of Reliability Standards (e.g., IRO-001-4, IRO-008-2, IRO-010-2, TOP-001-3, and TOP-003-3) that were developed since the Order was issued achieve the reliability objectives of PRC-001-1.1(ii), Requirement R2 and its sub-requirements. **Directives** Included in the explanation below is how these Reliability Standards address the directives in the Order at P 1441, 1444, 1445 and 1449 (#2 and #3). **Other** ~~Additionally, PER-005-3, Requirements R7 and R8 include RAS to ensure full coverage of the "operational functionality."~~ The phase "relay or equipment" in PRC-001-1.1(ii), Requirement R2 is clarified by the use

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		of the defined NERC Glossary term, "Protection System" and "RAS."
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected	PRC-001-1.1(ii), Requirements R2, R2.1., and R2.2. are proposed for retirement. Corrective action in Requirements R2, R2.1. and R2.2. is covered by:	**Introduction – Corrective Action** The directive at P 1449 (#3) of the Order states that: "…transmission operators must carry out corrective control actions, i.e., return a system to a stable state that respects system requirements…" This directive is addressed in the TOP/IRO standards that were developed since the Order was issued because the BA, RC, and TOP can issue Operating Instructions[22] to maintain the reliability of its respective area. The following describes how the TOP/IRO Reliability Standards achieve the reliability objective with regard to "corrective actions." **Corrective Action by the GOP – R2.1.**

[22] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Operating Instruction is defined as "[a] command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)"

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible. **PRC-001-1.1(ii) (Existing)**	**TOP-001-3 (Approved)** **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions. **R2.** Each Balancing Authority shall act to maintain the reliability of its Balancing Authority Area via its own actions or by issuing Operating Instructions. **TOP-003-3 (Approved)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to:	TOP-003-3 (*Operations Reliability Data*) Requirement R1 and part 1.2. that was developed since the Order was issued addresses corrective action by the GOP because the TOP will be aware of current Protection System and SPS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the TOP receives such notification. TOP-001-3 (*Transmission Operations*) Furthermore, the TOP will act to maintain the reliability of its Transmission Operator Area[23] (TOP Area) by issuing Operating Instructions to the GOP under TOP-001-3, Requirement R1. TOP-003-3 (*Operations Reliability Data*)

[23] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Transmission Operator Area is defined as "[t]he collection of Transmission assets over which the Transmission Operator is responsible for operating."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	Similarly, TOP-003-3, Requirement R2 and part 2.2. that was developed since the Order was issued, addresses corrective action by the GOP because the BA (i.e., Host BA[24]) will be aware of current Protection System and ~~SPS~~RAS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the BA receives such notification. The BA will act to maintain the reliability of its Balancing Authority Area[25] (BA Area) by issuing Operating Instructions to the GOP under TOP-001-3, Requirement R2. **Corrective Action by the TOP – R2.2.** TOP-003-3 (*Operations Reliability Data*)

[24] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Host Balancing Authority is defined as:

1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries.
2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.

[25] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Balancing Authority Area is defined as "[t]he collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.		Requirement R1 and part 1.2. that was developed since the Order was issued addresses corrective action by the TOP because the TOP will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the TOP receives such notification. TOP-001-3 (*Transmission Operations*) The TOP will act to maintain the reliability of its TOP Area by issuing Operating Instructions under TOP-001-3, Requirement R2. TOP-003-3 (*Operations Reliability Data*) Similarly, TOP-003-3, Requirement R2 and part 2.2. that was developed since the Order was issued addresses corrective action by the BA because the BA will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**IRO-010-2 (Approved)** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **IRO-001-4 (Approved)**	reliability. See the "shall notify" section(s) below for a full description of how the TOP receives such notification. The BA will act to maintain the reliability of its BA Area by issuing Operating Instructions under TOP-001-3, Requirement R2. IRO-010-2 (*Reliability Coordinator Data Specification and Collection*) Requirement R1 and part 1.2. that was developed since the Order was issued addresses corrective action by the RC because the RC will be aware of current Protection System and RAS status (change in status is implied) or degradation (including failure) that impacts System reliability. See the "shall notify" section(s) below for a full description of how the RC receives such notification. IRO-001-4 (*Reliability Coordination - Responsibilities and Authorities*) Under Requirement R1, the RC will act to address the reliability of its Reliability

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	R1. Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions."	Coordinator Area[26] (RC Area) by issuing Operating Instructions.
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its	PRC-001-1.1(ii), Requirements R2, R2.1, and R2.2. are proposed for retirement. The time frame for corrective action in Requirements R2, R2.1. and R2.2. is covered by:	**Introduction – Time frame for corrective actions** The directive at P 1441 directs the ERO to clarify the term "corrective action" consistent with the discussion in the Order when it modifies PRC-001-1 in the Reliability Standards development process. The reasoning for addressing a time frame for corrective actions is amplified in P 1443 of the Order, which states that: "As explained above *[in the previous paragraphs of the Order*], the requirement for system operators to take corrective control action when protective relay or equipment failure reduces system reliability should be treated

[26] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Balancing Authority Area is defined as "[t]he collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible. **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:		the same as the requirement for returning a system to a secure and reliable state after an Interconnection Reliability Operating Limit (IROL) violation, i.e., as soon as possible, but no longer than 30 minutes after a violation. A longer time limit would place an entity in violation of relevant IROL or TOP Reliability Standards."[27] At P 1444 of the Order, FERC directed NERC to consider the comments of the California PUC regarding the term "as soon as possible" as applicable to the maximum time frame for corrective action through the Standards development process. At P 1445 of the Order, FERC directed NERC, through the Reliability Standards development process, to determine the appropriate amount of time after the detection of relay failures, in which relevant

[27] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Interconnection Reliability Operating Limit is defined as "[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**TOP-001-3 (Approved)** **R1.** Each Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions.	transmission operators must be informed of such failures. The Order at P 1449 (#3) directs NERC to clarify that, after being informed of failures in relays or protection system elements that threaten reliability of the Bulk-Power System, transmission operators must carry out corrective control actions, i.e., return a system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes after they receive notice of the failure. **PRC-001-1.1(ii), R2.1. & R2.2. (time frame for corrective actions)** For the reasons explained below, a less than one-hour time frame criteria for corrective action will achieve the reliability objective directed in the Order at P 1441, 1444, 1445, and 1449 (#2 and #3). TOP-001-3 (*Transmission Operations*)

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2. Each Generator Operator and Transmission Operator shall notify reliability	**R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment.	Requirement R13 requires the TOP to ensure that a Real-time Assessment[28] ("RTA") is performed at least once every 30 minutes and initiate its Operating Plan[29] to mitigate a System Operating Limit[30] (SOL) exceedance identified as part of its Real-time[31] monitoring or RTA in TOP-001-3, Requirement R14. The RTA requires inputs to include current Protection System and RAS status (change in status is implied) or

[28] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Real-time Assessment is defined as "[a]n evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)"
[29] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Operating Plan is defined as "[a] document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan."
[30] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a System Operating Limit is defined as "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)"

[31] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), Real-time is defined as "[p]resent time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)"

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**IRO-008-2 (Approved)** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.	degradation (including failure) from a BA, GOP, and/or TOP. Under TOP-003-3 notification of these inputs must occur within a 30 minute time frame; otherwise, ~~an~~a valid RTA cannot be performed once every 30 minutes. Given the periodicity for obtaining the data and performing the RTA, the exposure (i.e., time frame) for taking corrective action "as soon as possible" is expected to be less than ~~an~~one hour. The TOP may issue Operating Instructions to maintain reliability upon the notification of Protection System or RAS status (change in status is implied) or degradation (including failure) because the exposure is not expected to exceed ~~an~~one hour. The TOP must act under TOP-001-3, Requirement R1 to maintain the reliability of its TOP Area via its own actions or by issuing Operating Instructions. IRO-008-2 (*Reliability Coordinator Operational Analyses and Real-time Assessments*), Requirement R4 requires the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	TOP-003-3 (Approved) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection	RC to ensure that an RTA is performed at least once every 30 minutes. The RTA requires inputs to include current Protection System and RAS status (change in status is implied) or degradation (including failure) from a BA, GOP, and/or TOP. TOP-003-3 (*Operations Reliability Data*) IRO-010-2 (*Reliability Coordinator Data Specification and Collection*) Under TOP-003-3 (TOP and BA) and IRO-010-2 (RC) notification of these inputs must occur within a 30 minute time frame; otherwise, ~~an~~a valid RTA cannot be performed once every 30 minutes. Given the periodicity for obtaining the data and performing the RTA, the exposure (i.e., time frame) for taking corrective action as soon as possible is expected to be less than ~~an~~one hour. The RC may issue Operating Instructions to maintain reliability upon the notification of Protection System or RAS status (change in status is implied) or degradation (including failure) because the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	System status or degradation that impacts System reliability. **IRO-010-2 (Approved)** **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	exposure is not expected to exceed ~~an~~one hour.
	IRO-001-4 (Approved) **R1.** Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.	IRO-001-4 (*Reliability Coordination - Responsibilities and Authorities*) The RC must act under IRO-001-4, Requirement R1 to maintain the reliability of its RC Area via its own actions or by issuing Operating Instructions.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	PRC-001-1.1(ii), Requirements R2, R2.1., and R2.2 are proposed for retirement. The time frame for notification in Requirements R2, R2.1. and R2.2. is covered by: **IRO-008-2 (Approved)** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **TOP-001-3 (Approved)**	**Introduction – Time frame for notifications and shall notify** The directive at P 1444 of the Order directed NERC to consider the comments of FirstEnergy about the time frame between actual failure and its discovery (i.e., notification) in relation to the maximum time frame for corrective action through the Standards development process. The Order at P 1445 and 1449 (#2) directed NERC to determine an appropriate amount of time after the detection of relay failures and the time in which relevant generation and transmission operators must be informed of such failure. **PRC-001-1.1(ii), R2.1. & R2.2. (time frame for notifications)** TOP-001-3 (*Transmission Operations*) For the reasons explained below concerning notification, it is inferred that the timeframe for notification must occur on at least a 30

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	**R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **TOP-003-3 (Approved)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis	minute interval because the ~~a~~ RTA performed by the RC (IRO-008-2) and TOP (TOP-001-3) once every 30 minutes requires the data to be ~~availability~~available on at least a 30 minute basis such that the exposure is less than one hour. TOP-003-3 (*Operations Reliability Data*) Notification in PRC-001-1.1(ii), Requirement R2.1. and R2.2. is addressed by TOP-003-3, Requirement R1, part 1.2. for TOP and Requirement R2, part 2.2. for BA that were developed since the Order was issued. Requirements R1 and R2 mandate that the TOP and BA ~~to~~ have provisions (i.e., inputs) for notification of Protection System and RAS status (change in status is implied) or degradation (including failures) that impacts System reliability. **PRC-001-1.1(ii), R2.1. (shall notify)** Based on the conclusions above (i.e., "time frame for corrective actions"), notifications

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible. **PRC-001-1.1(ii) (Existing)**	functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment. **R4.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring.	of the inputs of Protection Systems and RAS by the GOP must be provided on at least a 30-minute basis. The TOP/IRO set of standards that were developed since the Order was issued achieve the reliability objective of ensuring that the BA (i.e., Host BA) and TOP are notified of protective relay and equipment failures. TOP-003-3 (*Operations Reliability Data*) TOP-003-3, Requirement R1 mandates the TOP have a documented specification for the data necessary for the TOP to perform an Operational Planning Analysis ("OPA"),[32] Real-time monitoring, and RTA. Both the OPA and RTA, by definition, require an evaluation that reflects inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure). TOP-003-3, Requirement R3

[32] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), an Operational Planning Analysis is defined as "[a]n evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: **R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. **R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	**R5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: **5.1.** A mutually agreeable format **5.2.** A mutually agreeable process for resolving data conflicts **5.3.** A mutually agreeable security protocol. **TOP-003-3 (Approved) (included again for reference)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The	mandates the TOP distribute its documented specification to those entities that have the required data, which includes the GOP. TOP-003-3, Requirement R2 mandates the BA have a documented specification for the data necessary for the BA to perform its analysis functions and Real-time monitoring that include inputs from Protection System and RAS status (change in status is implied) or degradation that are necessary to maintain generation-Load-Interchange balance. TOP-003-3, Requirement R4 mandates the BA to distribute its documented specification to those entities that have the required data, which includes the GOP. TOP-003-3, Requirement R5 builds upon the previous Requirements R1, R2, R3, and R4 described above. Requirement R5 mandates that any GOP that receives a data specification (pursuant to Requirement R3 or R4) ~~to~~ satisfy the obligations of the documented specifications using: a mutually

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.	agreeable format, a mutually agreeable process for resolving data conflicts, and a mutually agreeable security protocol. Therefore, the reliability objective of PRC-001-1.1(ii) Requirement R2, R2.1 that mandates the GOP notify its TOP and Host BA of protective relay and equipment failures is addressed by the documented specification for the data required in TOP-003-3, Requirement R1, part 1.2. for TOP and Requirement R2, part 2.2. for the BA. The documented data specifications is required to be distributed by the TOP and BA and mandates the GOP, per TOP-003-3~~,~~ Requirement R5, provide current Protection System and RAS status (change in status is implied) or degradation that impacts System reliability. **PRC-001-1.1(ii), R2.2. (shall notify)** Based on the conclusions above (i.e., "time frame for corrective actions), notifications of the inputs of Protection Systems and RAS by the TOP must be provided on at least a 30-

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	TOP-003-3 (Approved) (included again for reference) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection	minute basis. The TOP/IRO set of standards that were developed since the Order was issued achieve the reliability objective of ensuring that the RC and the BA and TOP (i.e., the affected BA and TOP) are notified of protective relay and equipment failures. TOP-003-3 (*Operations Reliability Data*) TOP-003-3, Requirement R1, mandates the TOP have a documented specification for the data necessary for the TOP to perform an OPA, Real-time monitoring, and RTA. Both the OPA and RTA, by definition, require an evaluation to reflect inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure). TOP-003-3, Requirement R3 mandates the TOP distribute its documented specification to those entities that have the required data, which includes the BA, RC, and TOP. TOP-003-3, Requirement R2 mandates the BA have a documented specification for the data necessary for the BA to perform its

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	System status or degradation that impacts System reliability. **R2.** Each Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: **2.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.	analysis functions and Real-time monitoring, which would include inputs from Protection System and RAS status (change in status is implied) or degradation that are necessary to maintain generation-Load-Interchange balance. TOP-003-3, Requirement R4 mandates the BA distribute its documented specification to those entities that have the required data, which includes the BA, RC, and TOP. TOP-003-3, Requirement R5 builds upon the previous Requirements R1, R2, R3, and R4 described above. Requirement R5 mandates that any TOP that receives a data specification (pursuant to Requirement R3 or R4) ~~to~~ satisfy the obligations of the documented specifications using: a mutually agreeable format, a mutually agreeable process for resolving data conflicts, and a mutually agreeable security protocol. **Common to both the GOP and TOP** IRO-010-2 (*Reliability Coordinator Data Specification and Collection*)

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	IRO-010-2 (Approved) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	Requirement R1, mandates the RC have a documented specification for the data necessary for the RC to perform an OPA, Real-time monitoring, and RTA. Both the OPA and RTA, by definition, require an evaluation to reflect inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure). IRO-010-2, Requirement R2 mandates the RC distribute its documented specification to those entities that have the required data, which includes the BA, RC, and TOP. IRO-010-2, Requirement R3 builds upon the previous Requirements R1 and R2 described above. Requirement R3 mandates that a TOP that receives a data specification (pursuant to Requirement R2) ~~to~~ satisfy the obligations of the documented specifications using: a mutually agreeable format, a mutually agreeable process for resolving data conflicts, and a mutually agreeable security protocol.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
		Therefore, the reliability objective of PRC-001-1.1(ii) Requirement R2, R2.2. ~~that~~ mandates the TOP to notify its RC and affected BA and TOP of protective relay and equipment failures is addressed by the documented specification for the data required in TOP-003-3, Requirement R1, part 1.2. for the TOP and Requirement R2, part 2.2. for the BA, and IRO-010-2, Requirement R1 for the RC. The documented data specifications is required to be distributed by the TOP and will require the RC per IRO-010-2, Requirement R3 and the BA and TOP per TOP-003-3, Requirement R5 to provide current Protection System and RAS status (change in status is implied) or degradation that impacts System reliability.
PRC-001-1.1(ii) (Existing) **R3.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.	**PRC-027-1 (NERC Board approved)** The mapping of PRC-001-1.1(ii), Requirements R3, R3.1 and R3.2 are addressed in a different project. See Project 2007-06 System Protection Coordination	N/A

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. • Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition. **R3.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	(i.e., Phase 1) concerning proposed Reliability Standard PRC-027-1.	
PRC-001-1.1(ii) (Existing) **R4.** Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators,	**PRC-027-1 (NERC Board approved)** The mapping of PRC-001-1.1(ii), Requirement R4 is addressed in a different project. See Project 2007-06 System Protection Coordination (i.e., Phase 1)	N/A

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
Transmission Operators, and Balancing Authorities.	concerning proposed Reliability Standard PRC-027-1.	
PRC-001-1.1(ii) (Existing) **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems. **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	PRC-001-1.1(ii), Requirements R5, R5.1, and R5.2 are proposed for retirement. The notification in advance in Requirements R5, R5.1 and R5.2 is covered by:	**Introduction – Shall notify in advance** For the reasons explained under the "shall notify" sections above, the TOP will receive notifications of known current Protection Systems and RAS status (change in status is implied) or degradation (including failure) from the GOP and TOP under TOP-003-3 that was developed since the Order was issued. Advance notification to the TOP will occur through IRO-008-2, IRO-017-1 (*Outage Coordination*), and TOP-002-4 (*Operations Planning*) that were developed since the Order was issued, and through the existing TPL-001-4 (*Transmission System Planning Performance Requirements*). **PRC-001-1.1(ii), R5.1 and R5.2 (shall notify in advance)**

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating	**TPL-001-4 (Existing)** **R4.** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case	The following explains how the reliability objective of the GOP and TOP coordinating changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of other TOPs is met. TPL-001-4 (*Transmission System Planning Performance Requirements*) Requirement R4 (Requirement R2 is inferred by reference) focuses on the Planning Assessment[33] performed by either the PC or the TP with aspects of Protection Systems and RAS. Additionally, the projected Contingency conditions that are evaluated under TPL-001-4 by the PC and TP are considered by the TOP in performing an OPA.

[33] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Planning Assessment is defined as a "[d]ocumented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
conditions that could require changes in the Protection Systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems. **R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	analyzed in accordance with Requirements R2, Parts 2.1.4. and 2.4.3. The Corrective Action Plan(s) shall: **IRO-002-4 (Approved)** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **TOP-002-4 (Approved)** **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning	IRO-002-4 (*Reliability Coordination — Monitoring and Analysis*) Requirement R3 supports the inclusion of the Reliability Coordinator~~ in Requirement R8 of PER-005-3.~~. This function also has a responsibility to have knowledge (i.e. be familiar with the purpose and limitations) of Protection Systems and RAS since it is monitoring Facilities, the status of ~~SPSs~~RAS, and non-BES facilities. TOP-002-4 (*Operations Planning*) The approved TOP-002-4, Requirement R1 that was developed since the Order was issued requires the TOP to have an OPA that will allow the TOP to assess whether its planned operations for the next day (i.e., "in advance") within its TOP Area will exceed any of its SOLs. The OPA requires inputs to

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
PRC-001-1.1(ii) (Existing) **R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others: **R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.	Analyses, Real-time monitoring, and Real-time Assessments. **TOP-003-3 (Approved)** **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.	assess anticipated (pre-Contingency[34]) and potential (post-Contingency) conditions for next-day operations. The TOP when performing its next-day planning through an OPA, will receive the necessary data "in advance" under TOP-003-3 and evaluate the projected system conditions to assess ~~(using knowledge)~~ anticipated (pre-Contingency) and potential (post-Contingency) conditions for when generation, transmission, load, or operating conditions that could require changes in the other Transmission Operator's Protection Systems. By definition, an OPA evaluation shall reflect applicable inputs including Protection System and RAS status (change in status is implied) or degradation, but is not limited to: • load forecasts,

[34] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Contingency is defined as "[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.	**IRO-008-2 (Approved)** **R1.** Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System	• generation output levels, • Interchange, • known Protection System and ~~Special Protection System~~RAS status or degradation, • Transmission outages, • generator outages, • Facility Ratings, and • identified phase angle and equipment limitations. IRO-008-2 (*Reliability Coordinator Operational Analyses and Real-time Assessments*) IRO-008-2, Requirement R2 requires each RC to have coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances. These exceedances are identified as a result of an OPA being performed in IRO-008-2, Requirement R1 while considering the

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **IRO-017-1 (Approved)** **R3.** Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators. **R4.** Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or	Operating Plans for the next-day provided by each BA and TOP. Collectively, performing the OPA under TOP-002-4 using the necessary inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure), the Planning Assessment conducted under TPL-001-4, the jointly developed solutions under IRO-017-2, communication from the RC to the TOP under IRO-005-4, and the coordinated Operating Plan(s) under IRO-008-2 achieve the reliability objective of both PRC-001-1.1(ii), Requirements R5.1 and R5.2 for "when changes in generation, transmission, load, or operating conditions could require changes in the other Transmission Operator's Protection Systems." IRO-017-1 (*Outage Coordination*) IRO-017-1, Requirement R3 requires each PC and TP to provide its Planning Assessment to an impacted RC. IRO-017-1, Requirement R4 requires each PC and TP to jointly develop

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.	solutions with each respective RC for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.[35]
PRC-001-1.1(ii) (Existing) **R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Requirement R6 is being proposed for retirement. The monitoring and notification in Requirement R6 is covered by: **IRO-002-4 (Approved)** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability	**PRC-001-1.1(ii), R6 (monitoring and notification of RAS)** IRO-002-4 (*Reliability Coordination — Monitoring and Analysis*) The reliability objective for the monitoring of RAS is addressed by IRO-002-4, Requirement R3 for the Reliability Coordinator.

[35] Per the *Glossary of Terms Used in NERC Reliability Standards* (updated December 7, 2015), a Near-Term Transmission Planning Horizon is defined as "[t]he transmission planning period that covers Year One through five."

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	Operating Limit exceedances within its Reliability Coordinator Area. **TOP-001-3 (Approved)** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **10.1.** Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and **10.2.** Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency	TOP-001-3 (*Transmission Operations*) The reliability objective for the monitoring of RAS is addressed by TOP-001-3, Requirements R10 and R11 for the ~~BA~~TOP and ~~TOP~~BA, respectively, because they are required to monitor the status of a RAS. Notification of the change in status is addressed for the reasons explained under the "shall notify" sections above. In summary, the BA and TOP will receive notifications of inputs from known Protection System and RAS status (change in status is implied) or degradation (including failure) from the applicable GOP and/or TOP under TOP-003-3 that was developed since the Order was issued.

Standard: PRC-001-1.1(ii) – System Protection Coordination		
Requirement/Term in Standard	**Translation to Standard or Other Action**	**Comments**
	TOP-003-3 (approved) included by reference. See the section called, "shall notify."	

Violation Risk Factors and Violation Severity Level Justifications

Project 2007-06.2 Phase 2 of Protection System Coordination
PER-006-1 – Specific Training for Personnel

This document provides the Protection System Coordination Phase 2 Standard Drafting Team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for the proposed PER-006-1 – Specific Training for Personnel.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability

to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System: [2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

[1] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] *Id*. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels,[3] FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance[4]

Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties[5]

Guideline 2a: A violation of a "binary" type requirement must be a "Severe" VSL.

Guideline 2b: Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement[6]

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations[7]

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

[3] *Order on Violation Severity Levels Proposed by the Electric Reliability Organization*, 123 FERC ¶61,284 (2008).

[4] *Id*. at P20

[5] *Id*. at P22

[6] *Id*. at P32

[7] *Id*. at P35

VRF Justifications – PER-006-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	In this requirement, each Generator Operator (GOP) is required to train its plant personnel on the operational functionality of Protection Systems and Remedial Action Schemes that affect output of a generating Facility. It is unlikely that this requirement in the planning time frame, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, a violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition. The PRC-001-1.1(ii), Requirement R1 that will be replaced by PER-006-1, Requirement R1 has a VRF of High. The VRF of High is associated with the performance of the Balancing Authority (BA) and Transmission Operator (TOP) as they have a greater responsibility for ensuring reliable operation of the bulk electric system. The requirement for these entities to be familiar with the purpose and limitations of Protection System schemes in its area is addressed by the Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards and various requirements identified in the project mapping document. These requirements are appropriately assigned VRFs of Medium and High, therefore, does not require the GOP to also have a VRF of High. The Medium VRF is consistent with the training Requirements in the PER-005-2 (*System Personnel Training*) Reliability Standard, which includes the GOP, BA, TOP, and Reliability Coordinator.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This Requirement is consistent with the intent of Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.

VRF Justifications – PER-006-1, Requirement R1	
Proposed VRF	**Medium**
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The Requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The Requirement with a Medium VRF is consistent with the training Requirements in PER-005-1 and PER-005-2 that will become effective July 1, 2016.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: A VRF of Medium is consistent with the NERC VRF definition because GOP plant personnel could gain knowledge of the operational functionality of Protection Systems and Remedial Action Schemes that affect output of a generating Facility without specific training. It is unlikely that this requirement in the planning time frame, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, a violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This Requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

Proposed VSL – PER-006-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • one applicable personnel at a single Facility, or • 5% or less of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • two applicable personnel at a single Facility, or • more than 5% and less than or equal to 10% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • three applicable personnel at a single Facility, or • more than 10% and less than or equal to 15% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: • five or more applicable personnel at a single Facility, or • more than 15% of the total applicable personnel of the Generator Operator. **OR** The Generator Operator failed to provide training as described in Requirement R1 to its applicable personnel.

VSL Justifications – PER-006-1, Requirement R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is a gradated VSL for partial performance from a Lower to High VSL and a VSL of Severe for severe or complete failure of the Requirement.

VSL Justifications – PER-006-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The currently effective PRC-001-1.1(ii) did not have VSLs assignments. The proposed VSLs do not lower the current level of compliance because they are consistent with the approved PER-005-2, Requirement R6 for which PER-006-1, Requirement R1 is based upon.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This Requirement has a binary component and utilizes a VSL of Severe for complete failure in addition to incremental VSLs for partial performance. The VSLs provide a non-preferential way to apply violation levels to both small and large entities. Violations may be assessed at the greater of the number of personnel at the plant level or a percentage of personnel at the entity level. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the corresponding Requirement, and is therefore consistent with the Requirement.

VSL Justifications – PER-006-1, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

Evaluation of Proposed Definitions

Project 2007-06.2 – Phase 2 of System Protection Coordination

Introduction

The following definitions are proposed for revision under the Project 2007-06.2 – Phase 2 of System Protection Coordination. The definitions of "Operating Planning Analysis" (OPA) and "Real-time Assessment" (RTA) are used in the Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards.[1] To address the reliability objective of PRC-001-1.1(ii) – *Protection System Coordination*, Requirement R1 to "be familiar with the purpose and limitations of Protection System schemes in its area," the two definitions are being modified to include the phrase "…functions, and limitations…" to ensure the Transmission Operator (TOP), consider the functions and limitations of Protection Systems and Remedial Action Schemes (RAS) in their OPA and RTA evaluations. The PRC-001-1(ii) standard is not applicable to the Reliability Coordinator (RC), however, the modifications to the definitions affect this entity. Revising the definitions to require the RC and the TOP to integrate the functions and limitations (i.e., purpose and limitations) into its OPA and RTA will ensure that the Bulk Electric System (BES) is operated within System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL).

Proposed Definitions

This section includes the Reliability Standards and the associated requirements where the two modified terms are found. These two terms are not found within the proposed PER-006-1 standard, but are an integral part of the basis for the retirement of PRC-001-1.1(ii), Requirement R1. There are two significant revisions, (1) an administrative update to replace "Special Protection System" to "Remedial Action Scheme" (RAS), and (2) the addition of the phrase "…functions, and limitations…" to address the reliability objective of PRC-001-1.1(ii), Requirement R1 for the applicable TOP that must integrate the "functions and limitations" into these evaluations. The proposed definition revisions also have an effect on the Reliability Coordinator that is not applicable to PRC-001-1.1(ii). The bold text in the "Proposed Definitions" column accentuate the revisions.

[1] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order No. 817, 153 FERC ¶ 61,178 (2015).

Definitions (Effective January 1, 2017)	Proposed Definitions
Operational Planning Analysis An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)	**Operational Planning Analysis (OPA)** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to**:** load forecasts; generation output levels; Interchange; known Protection System and **Remedial Action Scheme** status or degradation**, functions, and limitations**; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Real-time Assessment An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)	**Real-time Assessment (RTA)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load**;** generation output levels**;** known Protection System and **Remedial Action Scheme** status or degradation**, functions, and limitations;** Transmission outages**;** generator outages**;** Interchange**;** Facility Ratings**;** and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Evaluation

The following is an evaluation of the potential impacts the modifications to the above definitions may have on the expected performance by the RC and TOP. The evaluation is limited to the Reliability Standards that will be or become in effect upon approval of the revised definitions.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-002-4 – Reliability Coordination – Monitoring and Analysis (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments.	The OPA definition revision has an impact on the RC in this requirement. The RC must include in its data exchange capability the "functions and limitations" of Protection Systems and RAS needed to perform an OPA.
IRO-008-2 - Reliability Coordinator Operational Analyses and Real-time Assessments (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall perform an *Operational Planning Analysis* that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its *Operational Planning Analysis* as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.	**Requirement R1** The OPA definition revision has an impact on the RC in this requirement. The RC must integrate the "functions and limitations" of Protection Systems and RAS in order to assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area. **Requirement R2** The OPA definition revision has no impact on the RC in this requirement. This requirement references that the results of the OPA are used by the RC to have a coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances.

<table>
<tr><th colspan="2">Operational Planning Analysis (OPA)</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Description and Change Justification</th></tr>
<tr><td>IRO-010-2 – Reliability Coordinator Data Specification and Collection
(Effective April 1, 2017)
R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to:
1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.
1.2. Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
1.3. A periodicity for providing data.
1.4. The deadline by which the respondent is to provide the indicated data.
R2. The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.</td><td>Requirement R1
The OPA definition revision has an impact on the RC in this requirement. The data needed by the RC regarding the "functions and limitations" of Protection Systems and RAS to support performing an OPA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of OPA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2).

Requirement R2
The OPA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the OPA to others.</td></tr>
</table>

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-014-3 - Coordination Among Reliability Coordinators (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1.** Criteria and processes for notifications. **1.2.** Energy and capacity shortages. **1.3.** Control of voltage, including the coordination of reactive resources. **1.4.** Exchange of information including planned and unplanned outage information to support its *Operational Planning Analyses* and Real-time Assessments. **1.5.** Provisions for periodic communications to support reliable operations.	The OPA definition revision has no impact on the RC in this requirement. Part 1.4 references that the RC must include information about planned and unplanned outages that support its OPA.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-002-4 – Operations Planning (Effective April 1, 2017) **R1.** Each Transmission Operator shall have an *Operational Planning Analysis* that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its *Operational Planning Analysis* as required in Requirement R1.	**Requirement R1** The OPA definition revision has an impact on the TOP in this requirement. The TOP must integrate the "functions and limitations" of Protection Systems and RAS in order to assess whether its planned operations for the next day within its TOP Area will exceed any of its SOLs. **Requirement R2** The OPA definition revision has no impact on the TOP in this requirement. The TOP is using information resulting from its OPA.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-003-3 – Operational Reliability Data (Effective April 1, 2017) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.1.** A list of data and information needed by the Transmission Operator to support its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessment.	**Requirement R1** The OPA definition revision has an impact on the TOP in this requirement. The data needed by the TOP regarding the "functions and limitations" of Protection Systems and RAS to support performing an OPA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of OPA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2.). **Requirement R2** The OPA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the OPA to others.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-002-4 – Reliability Coordination – Monitoring and Analysis (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*.	The RTA definition revision has an impact on the RC in this requirement. The RC must include in its data exchange capability the "functions and limitations" of Protection Systems and RAS needed to perform an RTA.
IRO-008-2 – Reliability Coordinator Operational Analyses and Real-time (Effective April 1, 2017) **R4.** Each Reliability Coordinator shall ensure that a *Real-time Assessment* is performed at least once every 30 minutes. **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a *Real-time Assessment* indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	**Requirement R4** The RTA definition revision has an impact on the RC in this requirement. The RC must include the "functions and limitations" among other prescribed inputs from the definition of RTA. **Requirement R5** The RTA definition revision has no impact on the RC in this requirement. The RC is notifying others based on the results of its RTA that an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-009-2 - Reliability Coordinator Actions to Operate Within IROLs (Effective January 1, 2016) **R2.** Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or *Real-time Assessment*. **R3.** Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the Reliability Coordinator's Real-time monitoring or *Real-time Assessment*.	**Requirement R2** The RTA definition revision has no impact on the RC in this requirement. The RC will be taking an action to prevent an IROL exceedance, as identified in the RC's RTA. **Requirement R3** The RTA definition revision has no impact on the RC in this requirement. The RC will be acting or directing others so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the RC's RTA.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-010-2 – Reliability Coordinator Data Specification and Collection (Effective April 1, 2017) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*. The data specification shall include but not be limited to: **1.1.** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments* including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*.	**Requirement R1** The RTA definition revision has an impact on the RC in this requirement. The data needed by the RC regarding the "functions and limitations" of Protection Systems and RAS to support performing an RTA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of RTA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2.). **Requirement R2** The RTA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the RTA to others.

<table>
<tr><th colspan="2">Real-time Assessment (RTA)</th></tr>
<tr><th>Requirement in Approved Standard</th><th>Description and Change Justification</th></tr>
<tr><td>IRO-014-3 - Coordination Among Reliability Coordinators (Effective April 1, 2017)
R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
1.1. Criteria and processes for notifications.
1.2. Energy and capacity shortages.
1.3. Control of voltage, including the coordination of reactive resources.
1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.
1.5. Provisions for periodic communications to support reliable operations.</td><td>The RTA definition revision has no impact on the RC in this requirement. Part 1.4 references that the RC must include information about planned and unplanned outages that support its RTA.</td></tr>
</table>

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-001-3 – Transmission Operations (Effective April 1, 2017) **R13.** Each Transmission Operator shall ensure that a *Real-time Assessment* is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or *Real-time Assessment*.	**Requirement R13** The RTA definition revision has an impact on the TOP in this requirement. The TOP must include the "functions and limitations" among the other prescribed inputs from the definition of RTA. **Requirement R14** The RTA definition revision has no impact on the TOP in this requirement. The TOP will be initiating its Operating Plan to mitigate a SOL exceedance identified in its RTA.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-003-3 – Operational Reliability Data (Effective April 1, 2017) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*. The data specification shall include, but not be limited to: **1.1.** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments* including non-BES data and external network data as deemed necessary by the Transmission Operator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and *Real-time Assessment*.	**Requirement R1** The RTA definition revision has an impact on the TOP in this requirement. The data needed by the TOP regarding the "functions and limitations" of Protection Systems and RAS to support performing an RTA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of RTA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2.). **Requirement R2** The RTA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the RTA to others.

Evaluation of Proposed Definitions

Project 2007-06.2 – Phase 2 of System Protection Coordination

Introduction

The following definitions are proposed for revision under the Project 2007-06.2 – Phase 2 of System Protection Coordination. The definitions of “Operating Planning Analysis” (OPA) and “Real-time Assessment” (RTA) are used in the Transmission Operations and Interconnection Reliability Operations and Coordination (TOP/IRO) sets of Reliability Standards.[1] To address the reliability objective of PRC-001-1.1(ii) – *Protection System Coordination*, Requirement R1 to “be familiar with the purpose and limitations of Protection System schemes in its area,” the two definitions are being modified to include the phrase “…functions, and ~~limits~~limitations…” to ensure the Transmission Operator (TOP), ~~and Reliability Coordinator (RC) that is not applicable to PRC-001-1.1(ii),~~ consider the functions and ~~limits~~limitations of Protection Systems and Remedial Action Schemes (RAS) in their OPA and RTA evaluations. The PRC-001-1(ii) standard is not applicable to the Reliability Coordinator (RC), however, the modifications to the definitions affect this entity. Revising the definitions to require the RC and the TOP to integrate the functions and ~~limits~~limitations (i.e., purpose and limitations) into its OPA and RTA will ensure that the Bulk Electric System (BES) is operated within System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL).

Proposed Definitions

This section includes the Reliability Standards and the associated requirements where the two modified terms are found. These two terms are not found within the proposed PER-006-1 standard, but are an integral part of the basis for the retirement of PRC-001-1.1(ii), Requirement R1. There are two significant revisions, (1) an administrative update to replace “Special Protection System” to “Remedial Action Scheme” (RAS), and (2) the addition of the phrase “…functions, and ~~limits~~limitations…” to address the reliability objective of PRC-001-1.1(ii), Requirement R1 for the applicable TOP that must integrate the “functions and ~~limits~~limitations” into these evaluations. The proposed definition ~~revision~~revisions also ~~has~~have an effect on the Reliability Coordinator that is not applicable to PRC-001-1.1(ii). The bold text in the “Proposed Definitions” column accentuate the revisions.

[1] Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards, Order No. 817, 153 FERC ¶ 61,178 (2015).

Definitions (Effective January 1, 2017)	Proposed Definitions
Operational Planning Analysis An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)	**Operational Planning Analysis (OPA)** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to**:** load forecasts; generation output levels; Interchange; known Protection System and **Remedial Action Scheme** status or degradation**, functions, and** ~~limits~~limitations; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Real-time Assessment An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)	**Real-time Assessment (RTA)** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load**;** generation output levels**;** known Protection System and **Remedial Action Scheme** status or degradation**, functions, and** ~~limits~~limitations**;** Transmission outages**;** generator outages**;** Interchange**;** Facility Ratings**;** and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Evaluation

The following is an evaluation of the potential impacts the modifications to the above definitions may have on the expected performance by the RC and TOP. The evaluation is limited to the Reliability Standards that will be or become in effect upon approval of the revised definitions.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-002-4 – Reliability Coordination – Monitoring and Analysis (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments.	The OPA definition revision has an impact on the RC in this requirement. The RC must include in its data exchange capability the "functions and ~~limits~~limitations" of Protection Systems and RAS needed to perform an OPA.
IRO-008-2 - Reliability Coordinator Operational Analyses and Real-time Assessments (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall perform an *Operational Planning Analysis* that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. **R2.** Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its *Operational Planning Analysis* as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.	**Requirement R1** The OPA definition revision has an impact on the RC in this requirement. The RC must integrate the "functions and ~~limits~~limitations" of Protection Systems and RAS in order to assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area. **Requirement R2** The OPA definition revision has no impact on the RC in this requirement. This requirement references that the results of the OPA are used by the RC to have a coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-010-2 – Reliability Coordinator Data Specification and Collection (Effective April 1, 2017) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: **1.1.** A list of data and information needed by the Reliability Coordinator to support its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments.	**Requirement R1** The OPA definition revision has an impact on the RC in this requirement. The data needed by the RC regarding the "functions and ~~limits~~limitations" of Protection Systems and RAS to support performing an OPA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of OPA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2). **Requirement R2** The OPA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the OPA to others.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-014-3 - Coordination Among Reliability Coordinators (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1.** Criteria and processes for notifications. **1.2.** Energy and capacity shortages. **1.3.** Control of voltage, including the coordination of reactive resources. **1.4.** Exchange of information including planned and unplanned outage information to support its *Operational Planning Analyses* and Real-time Assessments. **1.5.** Provisions for periodic communications to support reliable operations.	The OPA definition revision has no impact on the RC in this requirement. Part 1.4 references that the RC must include information about planned and unplanned outages that support its OPA.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-002-4 – Operations Planning (Effective April 1, 2017) **R1.** Each Transmission Operator shall have an *Operational Planning Analysis* that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). **R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its *Operational Planning Analysis* as required in Requirement R1.	**Requirement R1** The OPA definition revision has an impact on the TOP in this requirement. The TOP must integrate the "functions and ~~limits~~limitations" of Protection Systems and RAS in order to assess whether its planned operations for the next day within its TOP Area will exceed any of its SOLs. **Requirement R2** The OPA definition revision has no impact on the TOP in this requirement. The TOP is using information resulting from its OPA.

Operational Planning Analysis (OPA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-003-3 – Operational Reliability Data (Effective April 1, 2017) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: **1.1.** A list of data and information needed by the Transmission Operator to support its *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's *Operational Planning Analyses*, Real-time monitoring, and Real-time Assessment.	**Requirement R1** The OPA definition revision has an impact on the TOP in this requirement. The data needed by the TOP regarding the "functions and ~~limits~~limitations" of Protection Systems and RAS to support performing an OPA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of OPA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2.). **Requirement R2** The OPA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the OPA to others.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-002-4 – Reliability Coordination – Monitoring and Analysis (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*.	The RTA definition revision has an impact on the RC in this requirement. The RC must include in its data exchange capability the "functions and ~~limits~~limitations" of Protection Systems and RAS needed to perform an RTA.
IRO-008-2 – Reliability Coordinator Operational Analyses and Real-time (Effective April 1, 2017) **R4.** Each Reliability Coordinator shall ensure that a *Real-time Assessment* is performed at least once every 30 minutes. **R5.** Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a *Real-time Assessment* indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area.	**Requirement R4** The RTA definition revision has an impact on the RC in this requirement. The RC must include the "functions and ~~limits~~limitations" among other prescribed inputs from the definition of RTA. **Requirement R5** The RTA definition revision has no impact on the RC in this requirement. The RC is notifying others based on the results of its RTA that an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-009-2 - Reliability Coordinator Actions to Operate Within IROLs (Effective January 1, 2016) **R2.** Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or *Real-time Assessment*. **R3.** Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the Reliability Coordinator's Real-time monitoring or *Real-time Assessment*.	**Requirement R2** The RTA definition revision has no impact on the RC in this requirement. The RC will be taking an action to prevent an IROL exceedance, as identified in the RC's RTA. **Requirement R3** The RTA definition revision has no impact on the RC in this requirement. The RC will be acting or directing others so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the RC's RTA.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-010-2 – Reliability Coordinator Data Specification and Collection (Effective April 1, 2017) **R1.** The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*. The data specification shall include but not be limited to: **1.1.** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments* including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R2.** The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*.	**Requirement R1** The RTA definition revision has an impact on the RC in this requirement. The data needed by the RC regarding the "functions and ~~limits~~limitations" of Protection Systems and RAS to support performing an RTA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of RTA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2.). **Requirement R2** The RTA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the RTA to others.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
IRO-014-3 - Coordination Among Reliability Coordinators (Effective April 1, 2017) **R1.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: **1.1.** Criteria and processes for notifications. **1.2.** Energy and capacity shortages. **1.3.** Control of voltage, including the coordination of reactive resources. **1.4.** Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and *Real-time Assessments*. **1.5.** Provisions for periodic communications to support reliable operations.	The RTA definition revision has no impact on the RC in this requirement. Part 1.4 references that the RC must include information about planned and unplanned outages that support its RTA.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-001-3 – Transmission Operations (Effective April 1, 2017) **R13.** Each Transmission Operator shall ensure that a *Real-time Assessment* is performed at least once every 30 minutes. **R14.** Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or *Real-time Assessment*.	**Requirement R13** The RTA definition revision has an impact on the TOP in this requirement. The TOP must include the "functions and ~~limits~~limitations" among the other prescribed inputs from the definition of RTA. **Requirement R14** The RTA definition revision has no impact on the TOP in this requirement. The TOP will be initiating its Operating Plan to mitigate a SOL exceedance identified in its RTA.

Real-time Assessment (RTA)	
Requirement in Approved Standard	**Description and Change Justification**
TOP-003-3 – Operational Reliability Data (Effective April 1, 2017) **R1.** Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments*. The data specification shall include, but not be limited to: **1.1.** A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and *Real-time Assessments* including non-BES data and external network data as deemed necessary by the Transmission Operator. **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. **1.3.** A periodicity for providing data. **1.4.** The deadline by which the respondent is to provide the indicated data. **R3.** Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and *Real-time Assessment*.	**Requirement R1** The RTA definition revision has an impact on the TOP in this requirement. The data needed by the TOP regarding the "functions and ~~limits~~limitations" of Protection Systems and RAS to support performing an RTA would be included within Requirement R1, Part 1.1. Similarly in the most recent definition of RTA, the "status or degradation" of Protection Systems and Special Protection Systems (i.e., RAS) is addressed in its own requirement part (1.2.). **Requirement R2** The RTA definition revision has no impact on the RC in this requirement. The requirement performance is to distribute the data specification that is associated with the RTA to others.

Standards Announcement

Project 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 and Two Proposed Modified Definitions

Final Ballots Open through May 26, 2016

Now Available

Final ballots for **PER-006-1 – Specific Training for Personnel** and the proposed modified definitions of **"Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA)** are open through **8 p.m. Eastern, Thursday, May 26, 2016.**

Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pools may cast a vote. All ballot pool members may change their previously cast vote. A ballot pool member who failed to vote during the previous ballot period may vote in the final ballot period. If a ballot pool member does not participate in the final ballot, the member's vote from the previous ballot will be carried over as their vote in the final ballot.

Members of the ballot pools associated with this project may log in and submit their votes for the standard and definitions here. If you experience any difficulties using the Standards Balloting & Commenting System (SBS), contact Wendy Muller.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The voting results for the standard and definitions will be posted and announced after the ballots close. If approved, the standard and definitions will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 and Two Modified Definitions

Final Ballot Results

Now Available

Final ballots for **PER-006-1 – Specific Training for Personnel** and the modified definitions of **"Operational Planning Analysis" (OPA)** and **"Real-time Assessment" (RTA)** concluded **8 p.m. Eastern, Thursday, May 26, 2016.**

The voting statistics are listed below, and the Ballot Results page provides detailed results for the ballots.

	Quorum / Approval
PER-006-1	88.96% / 82.52%
Definitions of "Operational Planning Analysis" (OPA) and "Real-time Assessment" (RTA)	88.36% / 83.37%

Next Steps

The standard and definitions will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

BALLOT RESULTS

Ballot Name: 2007-06.2 Phase 2 of System Protection Coordination PER-006-1 FN 2 ST
Voting Start Date: 5/17/2016 3:08:36 PM
Voting End Date: 5/26/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 266
Total Ballot Pool: 299
Quorum: 88.96
Weighted Segment Value: 82.52

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	77	1	51	0.785	14	0.215	0	5	7
Segment: 2	8	0.5	4	0.4	1	0.1	0	2	1
Segment: 3	62	1	42	0.792	11	0.208	0	2	7
Segment: 4	17	1	15	1	0	0	0	0	2
Segment: 5	78	1	48	0.762	15	0.238	0	2	13
Segment: 6	43	1	29	0.707	12	0.293	0	0	2
Segment: 7	3	0.2	2	0.2	0	0	0	1	0
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	2	0.2	2	0.2	0	0	0	0	0
Segment:	6	0.5	4	0.4	1	0.1	0	1	0

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10									
Totals:	299	6.6	199	5.446	54	1.154	0	13	33

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Negative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

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1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey		Negative	N/A
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Negative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A

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1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Negative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
1	Hydro-Qu?bec Production	Aviance Freeman		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A

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1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Negative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich		Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A

1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Negative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Abstain	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A

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2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	N/A
3	AEP	Michael DeLoach		Negative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley		Negative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion	Connie Lowe		Affirmative	N/A

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	Resources, Inc.				
3	Duke Energy	Lee Schuster		Negative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Negative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker		Negative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Abstain	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A

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3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	North Carolina Electric Membership Corporation	doug white		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Negative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	N/A
3	Sacramento Municipal Utility District	Kimberly Neely		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Jim Cox		Affirmative	N/A

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3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	N/A

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4	Sacramento Municipal Utility District	Beth Tincher		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	AES - AES Corporation	Leo Bernier		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		None	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock		Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power	Shari Heino		None	N/A

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	Cooperative, Inc.				
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	N/A
5	Cleco Corporation	Stephanie Huffman		Negative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Essential Power, LLC	Gerry Adamski		Affirmative	N/A
5	Exelon	Ruth Miller		Negative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble		Negative	N/A
5	Great River Energy	Preston Walsh		None	N/A

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5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Wesley Maurer		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego		None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Robert Beadle		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and	Leo Staples		Negative	N/A

	Electric Co.				
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Oxy - Ingleside Cogeneration LP	Michelle D'Antuono		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Barbara Croas		Negative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Negative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Scotty Brown		Affirmative	N/A
5	SunPower	Bradley Collard		Affirmative	N/A

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5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		None	N/A
5	Talen Generation, LLC	Donald Lock		Negative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Negative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Negative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Negative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Negative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs		None	N/A
6	Cleco Corporation	Robert Hirchak		Negative	N/A
6	Colorado Springs	Shannon Fair		Affirmative	N/A

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	Utilities				
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Exelon	Maggy Powell		Negative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges		Negative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Adam Menendez		Negative	N/A
6	PPL - Louisville Gas	Linn Oelker		Affirmative	N/A

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	and Electric Co.				
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip		Affirmative	N/A
6	Salt River Project	William Abraham		Negative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Exxon Mobil	Jay Barnett		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		None	N/A

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8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	N/A

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BALLOT RESULTS

Ballot Name: 2007-06.2 Phase 2 of System Protection Coordination Modified Definitions of OPA and RTA FN 2 DEF
Voting Start Date: 5/17/2016 3:08:58 PM
Voting End Date: 5/26/2016 8:00:00 PM
Ballot Type: DEF
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 258
Total Ballot Pool: 292
Quorum: 88.36
Weighted Segment Value: 83.37

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	77	1	54	0.885	7	0.115	0	8	8
Segment: 2	7	0.5	2	0.2	3	0.3	0	1	1
Segment: 3	60	1	40	0.816	9	0.184	0	5	6
Segment: 4	16	1	12	0.923	1	0.077	0	1	2
Segment: 5	75	1	44	0.815	10	0.185	0	7	14
Segment: 6	43	1	29	0.763	9	0.237	0	3	2
Segment: 7	3	0.2	2	0.2	0	0	0	1	0
Segment: 8	3	0.2	2	0.2	0	0	0	0	1
Segment: 9	2	0.2	2	0.2	0	0	0	0	0
Segment:	6	0.5	5	0.5	0	0	0	1	0

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10									
Totals:	292	6.6	192	5.503	39	1.097	0	27	34

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

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1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Negative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		None	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey		Negative	N/A
1	CMS Energy - Consumers Energy Company	Bruce Bugbee		Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Kelly Silver		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A

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1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Negative	N/A
1	Hydro-Qu?bec Production	Aviance Freeman		Negative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley		None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A

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1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich		Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A

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1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Negative	N/A
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Negative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Negative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	N/A

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3	AEP	Michael DeLoach		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Julie Ross		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik		Affirmative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley		Negative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	N/A
3	Edison International - Southern California	Romel Aquino		Affirmative	N/A

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	Edison Company				
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker		Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Negative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	Northeast Missouri Electric Power	Skyler Wiegmann		Affirmative	N/A

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	Cooperative				
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	N/A
3	Sacramento Municipal Utility District	Kimberly Neely		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Jim Cox		Negative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T	Janelle Marriott Gill		Negative	N/A

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	Association, Inc.				
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Abstain	N/A
4	Sacramento Municipal Utility District	Beth Tincher		Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A

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4	Utility Services, Inc.	Brian Evans-Mongeon		Negative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Leo Bernier		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		None	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock		Negative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman		Negative	N/A

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5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Essential Power, LLC	Gerry Adamski		Affirmative	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble		Affirmative	N/A
5	Great River Energy	Preston Walsh		None	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River	Wesley Maurer		None	N/A

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	Authority				
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego		None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Negative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Negative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Oxy - Ingleside Cogeneration LP	Michelle D'Antuono		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Barbara Croas		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Abstain	N/A

5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Scotty Brown		Negative	N/A
5	SunPower	Bradley Collard		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		None	N/A
5	Talen Generation, LLC	Donald Lock		Negative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Negative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Negative	N/A

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5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Negative	N/A
6	City of Redding	Marvin Briggs		None	N/A
6	Cleco Corporation	Robert Hirchak		Negative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Exelon	Maggy Powell		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges		Affirmative	N/A
6	Great River Energy	Donna Stephenson		Affirmative	N/A

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6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Abstain	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Negative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip		Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas	Brad Lisembee		Negative	N/A

	and Electric Co.				
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Negative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Exxon Mobil	Jay Barnett		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
7	Oxy - Occidental Chemical	Venona Greaff		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		None	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity,	Rachel Coyne		Affirmative	N/A

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	Inc.				

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Exhibit H

Standard Drafting Team Rosters

Exhibit H-1

Standard Drafting Team Roster for Project 2007-06 System Protection Coordination

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Drafting Team Roster

Project 2007-06 System Protection Coordination

	Participant	Entity
Chair	Bill Middaugh	Tri-State G & T Association Inc.
Member	Forrest Brock	Western Farmers Electric Cooperative
Member	Samuel Francis	Oncor
Member	Jeffrey Iler	American Electric Power
Member	Kevin Wempe	Kansas City Power & Light Co.
Member	Philip Winston	Southern Company
NERC Staff	Al McMeekin – Standards Developer	North American Electric Reliability Corporation
NERC Staff	Lacey Ourso – Standards Developer	North American Electric Reliability Corporation
NERC Staff	Shamai Elstein – Senior Counsel	North American Electric Reliability Corporation

Exhibit H-2

Standard Drafting Team Roster for Project 2007-06.2 Phase 2 of System Protection Coordination

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Drafting Team Roster

Project 2007-06.2 Phase 2 System Protection Coordination

	Participant	Entity
Chair	Mark Peterson	Great River Energy
Vice Chair	Michael Cruz-Montes	CenterPoint Energy Houston Electric, LLC
Members	Glen Allegranza	Imperial Irrigation District
	Po Bun Ear	Hydro-Québec TransÉnergie
	Venona Greaff	Occidental Energy Ventures Corp.
	Jim Gunnell	Southwest Power Pool
	Scott Hayes	Pacific Gas and Electric
	Mark Kuras	PJM Interconnection, LLC
	Sam Mannan	Los Angeles Department of Water and Power
	Yubaraj Sharma	Luminant Generation Company, LLC
	RuiDa Shu	Northeast Power Coordinating Council
	Scott Watts	Duke Energy – Carolinas
PMOS Liaison	Brenda Hampton	Energy Future Holdings Corporation
NERC Staff	Scott Barfield-McGinnis – Senior Standards Developer	North American Electric Reliability Corporation
	Lacey Ourso – Standards Developer (Support)	North American Electric Reliability Corporation
	Shamai Elstein – Senior Counsel	North American Electric Reliability Corporation